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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Preparing for NERC Registration and Compliance with New IBR Rules

By Terry Brinker

Terry Brinker

As a former manager of registration for NERC and president and CEO of *Reliable Energy Advisors*, I have written articles about the risks and challenges of NERC regulations.

In my article *"Your Audit Report May Be Worthless,"* I warned of falling into the trap of thinking your organization has a strong compliance program because you passed an audit.

Today, I am sounding the alarm about potentially hundreds of facilities being swept up into the NERC regulatory world where fines and penalties can be as high as $1 million a day per violation.

Recently, NERC unveiled updated rules for inverter-based resources (IBRs), which are reshaping the landscape for utilities and energy producers. These new standards aim to enhance grid reliability and security in light of the increasing integration of renewable energy sources, such as solar and wind, into the electric grid.

For utilities not currently registered with NERC, these changes bring unique challenges and obligations. For entities that are registered and have additional facilities that will meet the new thresholds, more documentation will be needed.

To ensure a smooth transition, nonregistered entities must prepare proactively for NERC registration and adherence to NERC standards. This is no small feat, particularly for newcomers to NERC. In addition, unlike in the past where registration was a voluntary process, NERC has coordinated with reliability coordinators and transmission operators to identify entities that meet this new threshold.

Escaping NERC registration will be unlikely.

Understanding the New NERC Rules for Inverter-based Resources

NERC's updated rules focus on addressing the operational and cybersecurity challenges posed by IBRs. The new requirements emphasize:

Performance Validation: ensuring that IBRs can withstand and recover from disturbances without jeopardizing grid stability.

Data Sharing: mandating detailed operational data submissions for elective grid planning and operations.

Cybersecurity: strengthening the security framework to safeguard inverter-based systems against cyber threats.

These requirements reflect NERC's commitment to integrating renewable energy resources while maintaining the reliability and resilience of the Bulk Electric System.

Steps for Utilities Preparing for NERC Registration

For utilities not currently registered with NERC, the prospect of registration and compliance can be daunting. However, following a structured approach can streamline this transition:

Assess Applicability: Not all utilities are subject to NERC's rules. Entities must determine whether their operations meet NERC's criteria for registration. This includes evaluating the size, capacity and operational impact of their resources on the BES. If you have a facility (or facilities) with a 20-MVA nameplate rating and connected at 60 kV or higher, the countdown is on for you to register.

Conduct a Gap Analysis: Perform a thorough gap analysis to identify areas where your operations diverge from NERC standards. This involves:

- reviewing the new IBR requirements.
- identifying which NERC standards apply to your organization.
- assessing current operational, cybersecurity and data management practices.

Inverter-based resource with electronic power converter | *Claus Ableiter, CC BY-SA 3.0, via Wikimedia Commons*

Why This Matters

The abundance of renewable energy sources, such as solar and wind, being integrated into the electric grid creates the need for new standards to enhance reliability and security. Adhering to the standards will be no small feat, particularly for newcomers to NERC.

Stakeholder Soapbox

• identifying deficiencies and areas needing improvement.

Develop a Compliance Program: A robust compliance program is critical for meeting NERC standards. Key components include:

- Policies and Procedures: develop clear and comprehensive documentation of processes.
- Training: educate staff on NERC compliance obligations and the new IBR rules.
- Monitoring: implement tools for continuous monitoring and reporting of compliance metrics.

Engage with Industry Experts: Collaborate with NERC-registered utilities or consulting firms specializing in regulatory compliance. Their expertise can provide valuable insights into best practices and help navigate complex requirements.

Prepare for Audits and Registration: Mock audits and readiness assessments are essential for ensuring compliance. These activities simulate NERC's evaluation processes and allow utilities to address gaps before official audits.

Key Considerations for NERC Compliance

Documentation: maintain meticulous records of all compliance-related activities, including testing, training and incident responses.

Technology Investments: upgrade existing systems to meet performance and cybersecurity standards for IBRs.

Stakeholder Engagement: work closely with regulatory bodies, industry peers and technology providers to ensure alignment with NERC expectations.

Conclusion

The new NERC rules for IBRs signify a pivotal moment for utilities, especially those not yet registered with NERC. By proactively assessing their readiness, addressing operational gaps and implementing robust compliance programs, these entities can position themselves to meet NERC's standards effectively.

Early preparation not only ensures compliance but also fosters a more resilient and secure grid as renewable energy continues to grow in prominence. As the energy industry evolves, adhering to NERC's regulations is not merely a regulatory obligation — it is a critical step toward supporting a sustainable and reliable energy future.

Did I mention not adhering to NERC's regulations can result in fines and penalties up to $1 million a day per violation? ■

Terry Brinker is a 30-year industry professional with experience leading, facilitating and implementing improvements in power plant operations, control room operations, compliance and regulatory matters.

FERC/Federal News

Uncertainty Remains Around Energy Tariffs amid Last-minute Deals

Potential Impact of Trump's Measures on Electricity Markets Still a Big Unknown

By Jon Lamson and Robert Mullin

As the Trump administration forged last-minute agreements with Canada and Mexico to postpone steep new tariffs, the energy industry fretted about potential fallout for cross-border supply chains and wholesale electricity markets.

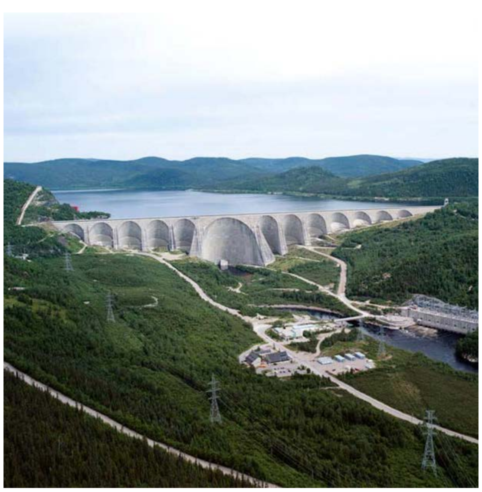
President Donald Trump signed a series of *executive orders* Feb. 1 creating new tariffs on Mexico, Canada and China, purportedly a response to the countries' failure to control drug trafficking and — in the case of the U.S. neighbors — illegal immigration.

The tariffs would include a 10% duty on Canadian energy, a 25% tariff on other Canadian goods and a 25% fee for all Mexican imports. On Feb. 3, the day before the tariffs were set to take effect, the U.S. announced a month-long pause on the tariffs on both countries, following agreements to increase security at both borders.

However, the administration is set to proceed with a new *10% tariff* on all imports from China, which comes on top of steep tariffs imposed by the Biden administration on battery components, electric vehicles and solar cells from the country. (See *Biden's New Tariffs Target China's Dominance in Solar, EV Markets*.)

Much of the uncertainty around the tariffs stemmed from vague language in the executive order regarding the lower tariffs for "energy or energy resources."

The *definition* referenced by the order classifies energy and energy resources as "crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water and critical minerals."



Hydro-Québec's Manic-5 Reservoir on the Manicouagan River | *Hydro-Québec*

Electricity is not explicitly mentioned in the order or the definition of energy or energy resources, and uncertainty remains regarding how the administration would levy a fee on electricity imports from Canada.

Responding to the order, energy executives representing a wide range of interests expressed concerns about potential cost impacts.

Jason Grumet, CEO of American Clean Power, said in a statement that the organization "is concerned that increasing the costs of energy production inputs will put upward pressure on consumer energy costs and diminish our capacity to unleash energy abundance."

He noted that components needed for solar panels, wind turbines and batteries are manufactured in Mexico and Canada and said the United States-Mexico-Canada Agreement has "been a positive factor in lowering American energy costs."

Connor Teskey, CEO of Brookfield Renewable, *told investors* Jan. 31 that added costs from tariffs on the renewable components will ultimately be passed on to ratepayers via more expensive power purchase agreements.

"The demand is stronger than ever before. … Should these things change the economics of a project, we will very simply push it through the PPA price," Teskey said.

Fossil fuel industry representatives also expressed concern about the tariffs. American Petroleum Institute CEO Mike Sommers noted that American refineries rely on crude imports from Canada, adding that Mexico is the top destination for exports of refinery products, while fossil fuel exports to China totaled over $14.4 billion in 2023.

"Energy markets are highly integrated, and free and fair trade across our borders is critical for delivering affordable, reliable energy to U.S. consumers," Sommers said.

Electrical Uncertainty

Significant uncertainty remains regarding how the tariffs would affect wholesale electricity markets, and whether the administration could even put a tariff on electricity imports.

Why This Matters

While uncertainty remains regarding what how tariffs would be applied, energy experts projected that the fees would likely cause significant cost increases throughout the industry.

A representative of the U.S. International Trade Commission declined to comment on the executive order, but highlighted a provision in the *Harmonized Tariff Schedule* that states electricity "shall not be subject to the entry requirements for imported merchandise set forth in section 484 of the Tariff Act of 1930."

They also linked a *2021 report* by the ITC that noted "imports of electrical energy are not considered to be subject to the tariff laws of the United States."

From the standpoint of electricity trading, Canadian provinces are more plugged into U.S. markets than to each other, according to the Canada Energy Regulator (CER), which regulates electricity exported from Canada.

"Most of Canada's electricity trade is with the U.S., as opposed to between provinces," the CER notes on its website.

The latest figures from the CER show Canada exported 32,750,232 MWh of electricity to the U.S. over January-November 2024 at an average price of $CAN61.45/MWh, while importing 21,471,172 MWh. The country's exports, largely produced by hydroelectric dams, were valued at nearly CAN$2.82 billion over that period, with imports estimated at about CAN$1.25 billion.

Ontario was the largest exporter, at 10,975,316 MWh, followed by British Columbia (5,895,148 MWh), Manitoba (5,682,762 MWh) and Québec (5,330,654 MWh).

But the relationship has long been symbiotic, with the U.S. receiving significant economic — and reliability — benefits from Canada's surpluses.

In New England, imports from Canada are an important part of the resource mix, even as a major drought has caused decreased hydro-

FERC/Federal News

power generation in Québec over the past two years.

Net imports across tie lines with Canada were used to meet about 5% of the New England's total electricity demand in 2024. As recently as 2022, net imports across these lines covered over 13% of the region's total electricity use. (See *New England Gas Generation Hit a Record High in 2024*.)

Even in a down year for hydropower in 2024, imports played a major role in preserving grid reliability during a pair of capacity scarcity events in the summer. Imports earned a combined $29 million in credits for performing during these periods, far more than any other resource type. (See *NEPOOL Markets Committee Briefs: Dec. 10, 2024*.)

A 10% increase in the cost of Canadian electricity would raise the market price paid to all participating resources when the imports are setting the market price. According to the ISO-NE *Internal Market Monitor*, external transactions — which include imports from both Canada and New York — were marginal 27% of the time in the day-ahead market in 2023.

"With the caveat that we are entering uncharted waters, at this time I do not expect this to have a major impact on electricity imports into New England," said Dan Dolan, president of the New England Power Generators Association. "NEPGA's observations are that those north-to-south flows tend to be less economically driven and more about what raw availability is available in excess of native load."

However, the tariffs could create challenges for long-term state contracts for power from Canada, he noted. Hydro-Québec has a long-term contract with Vermont, supplying the state with about a quarter of its total electricity needs.

The company has also signed long-term contracts with Massachusetts for the New England Clean Energy Connect (NECEC) transmission line, slated to come online at the end of 2025, and with New York for the Champlain Hudson Power Express, which is projected to finish construction in 2026. These projects could significantly increase the amount of power imported into the Northeast U.S. from Canada.

"Contracted electricity associated with a fixed cost may require regulatory or contractual adjustments," Dolan said. He also expressed concern that hydropower would be the only type of generation eligible for the lower 10% tariff, while other sources of power may face the full 25% duty because of the vague language in the executive order.

Larry Chretien, executive director of the Green Energy Consumers Alliance, *noted* that NECEC will provide about 15 to 20% of Massachusetts' electricity. A 10% tariff on these imports "makes the deal far less attractive," he said.

A representative of Hydro-Québec said the company is "closely monitoring" the situation, including potential impacts on short-term energy sales and long-term contracts, adding that it "will adjust our activities to limit impacts in Quebec."

Joe LaRusso, manager of the Clean Grid Program at the Acadia Center, a New England-based climate advocacy group, said he does not think tariffs would have a major effect on New England resource mix, but said they would likely lead to an overall increase in electricity prices.

"It's not good for a region that is already feeling the pinch of a significant energy burden," LaRusso said, adding that the cost increases would likely be the most pronounced in the winter, when the region relies most heavily on imported electricity.

ISO-NE said it is reviewing the proposed tariffs, as well as potential responses from Canadian officials.

"We are seeking guidance from the administration on what, if any, role [ISO-NE] will be required to have in implementing these tariffs," the RTO said. "We cannot speculate on what, if any, impact these actions will have on wholesale electricity prices or the level of imports into the region."

NYISO wrote in a statement that it "is actively pursuing guidance pertaining to the impact on electricity markets and which Canadian energy resources qualify."

Both Northeastern RTOs emphasized the close collaboration and ties between the power systems on both sides of the border.

BC Retaliation?

Western electricity markets faced a similar state of unease around the treatment of energy supplies from British Columbia, whose provincially owned utility, BC Hydro, shares control of hydroelectric output from the Columbia River system with its U.S. counterparts, the Bonneville Power Administration and the Army Corps of Engineers.

BC Hydro is closely integrated with the Western U.S. market through the operations of its marketing arm, Powerex, a sophisticated trader that markets the province's ample surpluses of hydro generation and engages in arbitrage trades throughout the Western Interconnection.

Powerex accounts for nearly all the province's exports into the U.S. and currently participates in CAISO's Western Energy Imbalance Market (WEIM), although it recently said it will eventually leave that market to join SPP's Markets+, for which it has been a key backer and the top funder. (See *SPP Markets+ Tariff Wins FERC Approval*.)

Asked what measures CAISO might have to take to account for the tariffs in its markets, ISO spokesperson Anne Gonzales told *RTO Insider*: "It's too early to tell what kind of direct impacts the energy tariffs might have on our market and operations. We are monitoring developments closely as these policies become more defined."

Powerex did not respond to a request for comment about the potential impact of the tariffs on its operations.

In December, *Victoria News* *reported* that British Columbia Premier David Eby said he would not rule out cutting the province's electricity flows to the U.S. in retaliation to tariffs on Canada.

"We are prepared to support retaliatory tariffs and response to the United States that gets their attention to help them understand what the consequences would be for British Columbians and what the consequence would be for Americans," Eby said during a Dec. 12 press conference, echoing a similar statement by Ontario Premier Doug Ford.

While Eby noted that British Columbia is generally a net importer of electricity, he also pointed to Powerex's strategy of importing electricity from other parts of the West at a "much lower" cost during times of surplus, then selling back into U.S. states such as Washington, Oregon and California during critical periods of peak demand.

Evidence of that value of that relationship could be seen in January 2024, with Powerex counted among suppliers from across the West that helped prevent multiple utilities in the U.S. Northwest from resorting to rolling blackouts during an extended deep freeze accompanied by low hydro supplies and a fault in the region's natural gas pipeline system. (See *Powerex Report Expands NW Cold Snap Debate*.)

Eby's office did not respond to a question about whether he might still follow through on the threat to withhold electricity supplies from the U.S. in the face of tariffs. ■

FERC/Federal News

Judge Issues Restraining Order on Trump Admin over Funding Pause

OMB Memo Leaves Fate of IIJA, IRA Programs Uncertain

By K Kaufmann and Michael Brooks

D.C. District Court Judge Loren AliKhan on Feb. 3 issued a temporary *restraining order* on the White House's Office and Management and Budget from pausing all federal grants and loans, including those committed by agencies through the Inflation Reduction Act and the Infrastructure Investment and Jobs Act.

The Trump administration's "actions appear to suffer from infirmities of a constitutional magnitude," AliKhan wrote. "The appropriation of the government's resources is reserved for Congress, not the Executive Branch. ...

"Defendants' actions in this case potentially run roughshod over a 'bulwark of the Constitution' by interfering with Congress' appropriation of federal funds. OMB ordered a nationwide freeze on pre-existing financial commitments without considering any of the specifics of the individual loans, grants or funds. It did not indicate when that freeze would end (if it was to end at all). And it attempted to wrest the power of the purse away from the only branch of government entitled to wield it."

The *memo* from OMB, issued Jan. 27, called for a review of all funding and stated that "federal agencies must temporarily pause all activities related to obligation or disbursement of all federal financial assistance, and other relevant agency activities."

This briefly put the federal bureaucracy into chaos, as it was unclear what exactly it applied to; state-level officials and U.S. representatives reported that constituents were complaining about not being to access Medicare and Medicaid.

White House spokesperson Karoline Leavitt later *clarified* to reporters that the memo did not apply to individual, direct assistance but rather "funding for the Green New Scam that has cost American taxpayers tens of billions of dollars. It means no more funding for transgenderism and wokeness across our federal bureaucracy and agencies. No more funding for Green New Deal social engineering policies."

A community solar project in Monroe, N.J. | *Heitman*

Why This Matters

Judge Loren AliKhan's temporary restraining order on the White House's attempts to pause all federal grants and loans, including those through the IRA and IIJA, contained a strong rebuke of the Trump administration's efforts to circumvent her original injunction, which has thrown state-level energy programs into limbo.

OMB *rescinded* the memo on Jan. 29 following a temporary injunction, issued by AliKhan just before it was due to take effect. But Leavitt *said* that while the administration had rescinded the memo to comply with the injunction, agencies would continue their efforts to review and possibly claw back funds not in line with the executive orders President Donald Trump issued on his first day in office, including his order on *Unleashing American Energy*. (See *Trump Will Need More than Executive Orders for US to Meet Rising Power Demand*.)

That threw many programs funded by the IRA and IIJA into limbo.

The Maryland Clean Energy Center was awarded $62 million from the IRA for the state's Solar for All program, created primarily to deploy community solar projects to help cut utility bills for low-income and disadvantaged communities. Maryland's grant was one of 49 state-level awards that EPA announced in April 2024.

Responding to *RTO Insider* on Jan. 31, EPA declined to identify any specific programs but stated that "the agency has paused all funding actions related to the Inflation Reduction Act and the Infrastructure Investment and Jobs Act at this time."

"As evidenced by the White House press

secretary's statements, OMB and the various agencies it communicates with appear committed to restricting federal funding," AliKhan wrote in her order. "If defendants retracted the memorandum in name only while continuing to execute its directives, it is far from 'absolutely clear' that the conduct is gone for good."

The case before AliKhan was brought by several groups, led by the National Council of Nonprofits. The judge noted that "plaintiffs have provided evidence that the scope of frozen funds appears to extend far beyond the reach of the executive orders."

"As just one example, a health center that provides medical, dental and behavioral health services to a rural community was denied access to grant funds," she wrote. "None of the seven executive orders listed in [the OMB memo] would seem to cover such activity. At oral argument, when asked about another declarant who was receiving a grant from the National Science Foundation, defendants could not give a clear answer as to why that recipient would be denied funds pursuant to the executive orders."

Solar, EV Chargers, Rural Renewables

Solar for All is not the only IRA-funded program on pause at MCEC. According to a spokesperson, three other program awards have been put on hold.

The center was named for a *$15 million award* from the IIJA-funded Charging and Fueling Infrastructure program, with the money going to install 58 EV charging stations statewide, along with workforce development efforts.

CFI is administered through the Department of Transportation and the Joint Office of Energy and Transportation. The pause means the planned charger deployment and workforce development will be on hold.

MCEC is also receiving federal funds to provide technical assistance for the Rural Energy for America Program, which provides loans and grant funding to farmers and rural small businesses to install renewable energy systems or energy-efficiency equipment and upgrades.

REAP is a Department of Agriculture program. The funding pause means that potential applicants cannot get the help they need to meet the requirements for applying for REAP dollars.

The Solar for All program is still in the planning stages, the spokesperson said. But without the IRA dollars, MCEC will not be able to find state funding to move ahead and reach its program goals, which include providing lower electric bills to 10,000 Marylanders.

MCEC and other Solar for All awardees have reported that they have not been able to access the program portal to submit specific funding requests.

Neither USDA nor DOE responded to repeated queries from *RTO Insider* on whether they have instituted a funding pause.

MISO and SPP were awarded $464 million from DOE's *Grid Resilience and Innovation Partnerships* program in support of five projects in the RTOs' Joint Targeted Interconnection Queue. GRIP is a $10.5 billion IIJA program aimed at expanding and upgrading the U.S. transmission system.

In response to a query from *RTO Insider*, MISO replied only that it is "continuing to coordinate with the project partners on meeting the grant award requirements."

The MISO-SPP award was one of 58 projects that received $3.46 billion in GRIP dollars in October 2023. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

DOE's Office of Clean Energy Demonstrations has canceled an in-person community meeting to discuss potential environmental impacts of the Appalachian Hydrogen Hub, one of seven regional hydrogen hubs funded with $7 billion from the IIJA.

The meeting was scheduled for Feb. 5 in Washington, Pa. In the email announcement, no reason was given for the cancellation, nor was information included on a potential rescheduling. ■

FERC/Federal News

Senate Confirms Trump's Energy, Interior Secretaries

By James Downing

The U.S. Senate on Feb. 3 voted to confirm President Donald Trump's nominee to be secretary of energy, Chris Wright, 59-38, days after confirming Doug Burgum as secretary of the interior.

Senate Energy and Natural Resources Committee Chair Mike Lee (R-Utah) said Wright, CEO of Liberty Energy, would reverse the climate policies championed by the Biden administration's Department of Energy.

"For the last four years, when Americans opened their energy bills, they didn't see 'climate plans'; they saw costs piling up and questions they couldn't answer," Lee said. "With Chris Wright as secretary of energy, I am confident that we can reverse the irresponsible policies of the Biden administration and prioritize affordable and reliable energy."

Lee's counterpart in the House, Energy and Commerce Committee Chair Brett Guthrie (R-Ky.), also welcomed Wright's confirmation.

"Maintaining affordable and reliable energy will be key to both our economic success and national security in the years ahead," Guthrie said. "Secretary Wright understands the importance of utilizing our domestic energy resources to secure the grid, lower prices and create family-sustaining jobs."

Burgum, former governor of North Dakota, was confirmed 78-19 on Jan. 30. Both he and Wright cleared the floor within two weeks of making it out of the Energy and Natural Resources Committee, which approved them both Jan. 23. (See *Trump Energy, Interior Cabinet Picks Easily Pass Committee Votes*.)

"Gov. Burgum's confirmation today is a win for our public lands and a win for American energy," Lee said. "He has spent his career bringing people together to solve problems and earned the trust of tribes, businesses, conservationists and working families alike. He understands that we cannot regulate our way into prosperity."

Advanced Energy United welcomed the two new secretaries with statements arguing that its members' technologies — such as solar, wind, storage and advanced transmission — are part of an affordable, reliable grid.

"Our industry shares with Secretaries Burgum and Wright their ambition to lower energy costs, strengthen the electric grid and make

Chris Wright | *Senate Energy and Natural Resources Committee*

America energy abundant," CEO Heather O'Neill said. "We urge the incoming administration to embrace and enable the market forces and investments that are allowing states to leverage advanced energy solutions to meet their energy needs. Advanced energy technologies provided 96% of all new electricity added to America's power grid in 2024 and remain the lowest-cost way to reliably meet growing electricity demand."

Electric Power Supply Association CEO Todd Snitchler argued that Wright and Burgum should support competitive markets as the power industry seeks to meet higher demand from data centers.

"Properly functioning competitive wholesale electricity markets have a proven track record of delivering the reliable power needed to fuel this growth while adapting to new technologies and market conditions and shielding consumers and taxpayers from investment risks," Snitchler said. "These benefits are made all the more salient as recent news about DeepSeek and other AI tools has underscored the likely quickly changing dynamics of the industry as it develops."

American Clean Power CEO Jason Grumet congratulated Burgum on his new role and said the clean energy industry wanted to work with the new administration.

"We are eager to support the administration's efforts to make American energy dominance a reality," Grumet said. "This whole-of-government approach will be crucial to aligning agencies to advance an 'all-of-the-above' energy strategy which is essential to achieving these goals."

National Rural Electric Cooperative Association CEO Jim Matheson said his members often have to deal with Interior, as they operate on federal lands.

"Electric cooperatives serve 56% of the nation's landmass and operate on more public lands than any other type of utility," Matheson said. "We look forward to partnering with Secretary Burgum and his team to alleviate the layers of bureaucratic red tape in our land and species management agencies that so often stand in the way of electric system operations, reliability and affordability. By doing so, cooperatives can more effectively operate and maintain their systems, harden the electric grid against wildfire and other threats and meet surging electricity demand." ■

Overheard at USEA State of the Energy Industry Forum 2025

NARUC to Focus on Demand Growth at Conferences

WASHINGTON — The National Association of Regulatory Utility Commissioners will hold roundtables on demand growth at each of its major conferences this year, Executive Director Tony Clark said at the United States Energy Association's State of the Energy Industry Forum on Jan. 23.

The former FERC commissioner and North Dakota regulator was asked how NARUC is addressing the challenges of data centers and demand growth. NARUC is very good at convening and educating, he answered, which is exactly what it will do on the topic beginning with the Winter Policy Summit in Washington, D.C.

Each roundtable will have "21 people, who at each of the meetings [are] going to have a deep dialogue on just these issues. … Seven state commissioners, seven folks from the utility industry and seven folks from the demand side of the equation — hyperscalers, data centers, things like that — [will be] encouraging this kind of dialogue so we can get to, hopefully, some of the answers."

Todd Snitchler, CEO of the Electric Power Supply Association, pointed to the combination of different state clean energy goals and demand growth as driving market transformation.

Varying state climate goals have "challenged market operators in a way that is not something they were originally constructed to do," Snitchler said. "So, we're going through some growing pains in order to sort out how we deliver" reliable, affordable and increasingly clean power, he said.

Talking affordability, reliability and demand growth at the USEA State of the Energy Industry Forum (from left): Mark Menezes, USEA; Michelle Bloodworth, America's Power; Malcolm Woolf, National Hydropower Association; Tony Clark, NARUC; and Todd Snitchler, EPSA.. | *© RTO Insider LLC*

Why This Matters

The U.S. has multiple options for meeting the growing demand from AI and data centers, from energy efficiency to nuclear fusion — and untangling the challenges of state and federal permitting is going to take innovative regulatory models and dedicated cross-industry collaboration.

The restarting of decommissioned nuclear plants — Palisades in Michigan and Three Mile Island in Pennsylvania — possibly to power co-located data centers "suggests that restructured markets are finding ways to deliver," he said. "They are working to define innovative approaches in order to supply power in a way that is cost effective, and they can deploy perhaps new mechanisms in order to achieve those outcomes. That's going to require a bit of a different approach and different thinking."

With estimates of coming demand growth still rising, what's needed are "rules of the road that make it clear about who pays how much [and] what is required for approvals. That will accelerate the process; that will help everyone navigate the situation in a fashion that I think is better and helps achieve the policy goals that the country has," he said.

Clark called for federal-state cooperation to get more generation and transmission online, arguing that federal roadblocks on permitting are often the primary cause of delays, rather than state processes.

But he cautioned that simply federalizing permitting may not solve the issues. "It will actually promote longer lead times if you don't reform the underlying problems that the federal government is having. … The federal government and states fighting over some issue rarely turns out well."

Leveraging state resources and regulatory models must be part of the process. Clark is optimistic about working with new FERC Chair Mark Christie, also a former state regulator, who "has shown a willingness to really listen to the concerns of the states," he said. (See *President Trump Names Mark Christie as FERC Chair*.)

When Nuclear?

Data centers' voracious appetite for power is creating new momentum for nuclear energy, but questions remain about when new plants, including small modular reactors, will come online.

Maria Korsnick, CEO of the Nuclear Energy Institute, pointed to a growing industry pipeline of permitting applications at the Nuclear Regulatory Commission, including 23 for plant upgrades or license extensions.

"Just in the next few years, we expect nine site permit applications," she said. "We expect five construction permits. We have two construction and operating permits," along with the restarts of Palisades and Three Mile Island.

But to get new plants online, tax credits and other federal incentives for nuclear will be imperative, she said; for example, the Department of Energy's Advanced Reactor Demonstration Program, which is providing $2.5 billion to support early deployments of SMRs.

Federal support will be critical for "early mover support" to building out critical supply chains pipelines for advanced nuclear, she said.

Arshad Mansoor, CEO of the Electric Power Research Institute, said the goal should be for nuclear to become "a catalog technology … that you can go to a catalog and buy. Gen III, Gen IV, small modular reactors … these are not catalog technologies, yet we need to deploy at least 10 of them before they become a catalog technology."

With ongoing support from Congress and the National Laboratories, Mansoor said, next generation nuclear could go catalog in five or six years.

Andrew Holland, CEO of the Fusion Industry Association, said his members now estimate nuclear fusion plants will be putting electricity on the grid in the 2030s, "with about 85% saying in the first half" of the next decade.

Fusion — which could produce massive amounts of power by combining, rather than splitting, atoms — "is now moving from the place where it has that long, long horizon, to something that is indeed on the horizon and coming closer, and the reason is because we're moving from the National Labs and the universities into the marketplace," Holland said.

Started four years ago, the FIA has 40 members working to commercialize fusion and 100 affiliate members, representing "the whole big tent of … both supply chain and end users for fusion power," he said. Another key sign of growth, the industry has raised more than $8 billion in private investment.

In 2023, Microsoft signed a power purchase agreement with fusion startup Helion, with a delivery date of 2028. Holland said fusion could be a comprehensive solution to a range of energy industry challenges "when we get it." It will be always available and abundant, and he argued the U.S. has to get serious about winning the global race for it.

"Fusion should be treated just like every other emerging energy source has been treated," he said. "That means public-private partnerships should be funded at significant levels," similar to the ARDP.

Wildfires a 'Societal Problem'

The closest reference to climate change came in a taped message from Pat Vincent-Collawn, interim CEO of the Edison Electric Institute. With wildfires still burning in Southern California, Vincent-Collawn acknowledged that fire threats have become "a year-round problem," but they are "a societal problem that requires societal solutions."

A major policy priority for EEI is the development of a comprehensive national strategy that focuses on adaptation, including "community protection, wildfire prevention, responsible investment and rapid recovery," she said.

The Electricity You Don't Use

Paula Glover, president of the Alliance to Save Energy, kicked off the final panel of the day by noting that no one thus far had talked about energy efficiency, which she argued should be "foundational" in discussions about demand growth.

"It almost sounds as if we assume there is nothing we can do," and that demand will just continue to rise, Glover said. "But what really makes an impact on customers, whether they are business customers, large and small, or residential consumers, is the ability of people to use energy for whatever they need, but not as much."

Whatever generation technology is used, efficiency should be a "first field, [so] that thing that you don't use has far more value."

One priority for ASE going forward is working with RTOs, such as MISO and PJM, on their implementation of FERC Order 2222, specifically as it applies to the integration of virtual power plants on the grid and measuring the value of the efficiency they can provide, Glover said.

She also believes that even as AI becomes pervasive, it will become more efficient. "So, when we're thinking about increased generation [and] demand because of AI, we also know that 20 years from now, what AI uses today is probably going to go down because of that technology.

"And so, the argument is always, if you think about what industry can do when you're planning, then you're not building as much; you're not buying as much; people aren't using as much," she said. "And we know it's just going to get better, better, better as time goes on." ■

— K Kaufmann

CAISO/West News

BPA Employees Confront Trump's 'Fork in the Road'

Staff Caught up in President's Effort to Shrink Government Despite Agency's Self-funding

By Robert Mullin

Employees of the Bonneville Power Administration received the same buyout offer from the Trump administration as millions of other federal workers, staff have confirmed to *RTO Insider*.

The move came despite the federal power marketing administration's status as a self-funding entity and its key role in Northwestern electricity generation and transmission and regional fish conservation efforts.

BPA also operates a balancing authority area covering about 300,000 square miles, which encompasses large parts of Oregon, Washington, Idaho and Montana, and smaller sections in California, Nevada, Wyoming and Nevada.

The agency is headed by Administrator John Hairston, who has served in that role since January 2021.

The Trump administration emailed the buyout offers to about 2.3 million federal employees through the Office of Personnel Management (OPM) in a Jan. 28 *message* titled, "Fork in the Road."

The message instructed recipients to type the word "Resign" into the subject line and reply if they want to accept the offer of the "deferred resignation" arrangement, with the promise they'd be provided a severance package consisting of eight months' pay and benefits through Sept. 30, the end of the federal fiscal year. Employees were directed to respond by Feb. 6.

The email explained that the move is part of an effort to "reform" the federal workforce around "four pillars," consisting of a policy to require most remote workers to return to their physical offices five days a week; a "performance culture" that will "insist on excellence at every level"; a "more streamlined and flexible workforce" resulting from downsizing; and "enhanced standards of conduct" intended to retain "employees who are reliable, loyal trustworthy and who strive for excellence in their daily work."

BPA headquarters in Portland, Ore. | *Bonneville Power Administration*

The administration has said it expects 5 to 10% of the federal workforce to accept the offer, which observers have said looks to be modeled closely on the approach that Elon Musk used with employees at Twitter (now X) after he assumed ownership of the social media platform in 2022. Trump picked Musk to lead efforts at the unofficial "Department of Government Efficiency," charged with reducing the size of federal operations.

'Ridiculous Deal'

A BPA employee who spoke on background to *RTO Insider* said fellow staff members had expressed concern about the unexpected development but were generally "keeping their heads down" and continuing to perform their duties amid the uncertainty.

Portland-based BPA employs more than 3,000 people and manages the output from 31 hydroelectric dams in the Federal Columbia River Power System with a combined capacity of about 22,440 MW. The agency additionally operates more than 15,000 miles of transmission lines — about 75% of the Northwest grid.

Asked to comment about the potential impact of the order, a BPA spokesperson referred *RTO Insider* to the agency's parent agency, the U.S. Department of Energy, for a response.

DOE did not respond to a series of questions seeking clarity on several points, including:

- what steps DOE is taking to evaluate the operational impact on BPA and the other three PMAs of potentially high staff turnover in such a short period of time;
- if DOE is aware of how and when OPM will inform the department and the PMAs about specific resignations at the agencies;
- whether DOE has been provided guidance by the administration about how BPA and the other PMAs should implement the "four pillars" outlined in the buyout memo or been given a time frame for doing so; and
- whether DOE expects BPA, the other PMAs and the Tennessee Valley Authority to be in any way insulated from the measures laid out in the email based on their self-funding models.

Why This Matters

A rapid loss of staff could significantly disrupt operations at BPA, which manages one of the largest balancing authority areas in the West and controls 75% of the Northwest's transmission grid, along with marketing the output from the region's extensive network of federal hydroelectric dams.

In an email to *RTO Insider*, U.S. Sen. Jeff Merkley (D-Ore.) said Trump "has no authority to offer this ridiculous deal, nor does he have authority to guarantee it. If folks take this so-called deal, they could be left high and dry by the president.

"Nonpartisan BPA professionals work hard to provide reliable, affordable electricity across the Pacific Northwest, and citizens and local businesses depend on the agency for its critical services."

The offices of Sens. Ron Wyden (D-Ore.) and Maria Cantwell (D-Wash.) did not respond to requests for comment as of press time.

Scott Simms, executive director of the Portland-based Public Power Council — whose membership consists of BPA's "preference" customer base of publicly owned utilities that purchase low-cost power from the agency — said the group is "gravely concerned" by the development.

"BPA is funded by Northwest ratepayers and not taxpayers, and its mission supports the Northwest economy; ensures the flow of reliable, domestically produced electricity; and provides employment in rural areas," Simms said in an email. "I think if certain decision-makers knew that, they would do everything possible to retain this valuable workforce. This will be important for us to emphasize in the weeks and months ahead so we don't suffer unintended consequences to our power system and our region's communities that depend on it." ■

CAISO/West News

Day-ahead Seams Issues Could Take Years to Resolve, BPA Staff Says

Seams Agreements Complex, Lengthy, Agency Says

By Henrik Nilsson

PORTLAND, Ore. — The Bonneville Power Administration would have to strike several types of agreements, many of which are complex and could take years to implement, to tackle seams that could arise if BPA joins a day-ahead market, agency staff said during a workshop Jan. 30.

BPA has generation and load all over the Pacific Northwest that will be impacted by market seams irrespective of whether the agency chooses to join SPP's Markets+ or CAISO's Extended Day-Ahead Market (EDAM). With 38 balancing authorities and over 30 transmission service providers, the Western interconnection is already complex, Todd Kochheiser, senior electrical engineer at BPA, said *during a presentation* on the seams issue.

"Anybody that's operated in the Pacific Northwest, either commercially or [in a] more traditional sense, knows that a lot of the BAAs in the Northwest are non-contiguous," Kochheiser said. "They're sort of stitched together using a collection of native transmission and third-party transmission service providers. It's a fairly messy landscape when you look at it from that perspective."

BPA's own BAA is similarly non-contiguous and located in six states while adjacent to 18 BAAs, Kochheiser noted.

The creation of day-ahead markets and associated real-time markets "will change existing market and [reliability coordinator] footprints in the [Pacific Northwest] and introduce new seams on top of those that already exist," a BPA staff presentation stated.

For BPA, this means ensuring seams agreements and their implementation "address concerns that are unique and specific to Bonneville," Kochheiser said.

But getting there is tricky. BPA must strike complex agreements with multiple parties that can take years to negotiate and implement. Agreements between RTOs can range from 200 to 400 pages, according to the presentation.

However, staff pointed out that BPA has experience negotiating agreements that can guide the agency. For example, the agency already has a Coordinated Transmission Agreement (CTA) with CAISO, Kochheiser said.

Still, it took a long time to get BPA and CAISO to agree on terms for the existing CTA contract, and it took even longer to implement it, according to Kochheiser.

"It probably took twice or three times longer to implement than it did to negotiate and sign it," he said, adding that "signing an agreement isn't the touchdown. You're at the 50-yard line."

Proponents of both Markets+ and EDAM have each argued that their respective preferred market choice provides a better solution for *resolving seams*.

'Difficult Headache'

A *study* published in February 2024 by the Western Power Trading Forum (WPTF) and Portland, Ore.-based Public Generating Pool found that a seam between EDAM and Markets+ likely would create challenges beyond those seen at the boundaries of the full RTOs in the Eastern U.S., given that each market still would contain operating seams within them.

Fred Heutte, a senior policy analyst at the Northwest Energy Coalition (NWEC), has pointed to this study to argue that, given BPA's size, the agency's positions would be even more complicated if it joins Markets+ while many of its neighbors join EDAM because both markets effectively would be running on top of its balancing authority area.

Heutte reiterated those concerns during the Jan. 30 workshop, saying splitting the West into two major markets will "be a permanent, expensive, difficult headache, just on the agreement side."

Actual implementation will not be any easier, Heutte said. There's a risk that seams agreements cannot identify unforeseen issues, "and we see distortion in the market system operation that costs a lot of money and a lot of time."

"There's been a sort of free-floating thing 'Oh, we can just deal with this with the seams agreement.' It's not going to be so easy, and it's going to be expensive," Heutte added.

But proponents of Markets+ have a different view. For example, Jeff Spires, director of power at Powerex, argued in September that Markets+ *provides a much more equitable solution* to tackling market seams than EDAM. Spires warned about joining EDAM, saying participants would be subject to the whims of CAISO and its purported preference toward California.

During the Jan. 30 workshop, Laura Trolese with The Energy Authority said she understands the concerns about BPA joining Markets+ as it "might seem like it's creating many more seams than if BPA were to join EDAM." However, she added it appears that EDAM still has "a lot of seams that are pretty complex."

Libby Kirby, BPA's market initiatives policy lead, said BPA is not solely responsible for creating seams.

"The decision of all of us ultimately resulting in two markets creates an additional seam," Kirby said. "It is not only BPA that has made a decision. I want to make sure that's clear."

BPA has said it will issue a draft day-ahead market decision in March and a final decision in May. ■

BPA staff and stakeholders meet to discuss the agency's day-ahead market decision in Portland, Ore., on Jan. 30. | *© RTO Insider LLC*

Why This Matters

In urging BPA to join CAISO's EDAM instead of SPP's Markets+, supporters of the ISO market have argued that a West divided by a market seam won't realize the full potential economic benefits of a more organized electricity market.

CAISO/West News

BPA Considers Impact of Fees in Day-ahead Market Choice

Agency Must Weigh Implementation, Annual Fees for Participating in Markets+, EDAM

By Henrik Nilsson

PORTLAND, Ore. — The Bonneville Power Administration could face high implementation fees and operating costs under both SPP's Markets+ and CAISO's EDAM, but exact amounts are still in flux, and various factors could soften the financial blow, staff members said during BPA's member meeting Jan. 29.

Rachel Dibble, vice president of bulk power marketing at BPA, told *RTO Insider* that implementation fees are "one part of the puzzle" in the agency's final market decision. The agency will weigh those considerations against results of production cost models, "as well as all the other quantitative elements that weren't included in the production cost model," Dibble added.

"As far as the magnitude of those numbers, they probably sit more in the ongoing revenue … and costs that we would generate from participating in the market," Dibble said. "I would expect over time, we would make back all of the money that we would be investing in getting ready to enter a market. So, we will certainly consider them, and they will be part of the decision."

SPP estimates that Phase 2 implementation costs across the entire Markets+ footprint will be approximately $150 million, and it is unclear exactly how much of that BPA would be responsible for. Agency staff have noted it is probably about $25 million, which is more than the $2.5 million to $3 million in implementation fees expected under an EDAM scenario.

However, CAISO has also projected $29 million annually in grid management charge fees for the BPA BAA across all scheduling coordinators. The charge is a transactional fee applied to each transaction, and the agency itself would "bear only a share of these charges based on its activities representing its loads and resources in the market," according to a staff presentation.

Andy Meyers, market initiatives policy lead with BPA, noted the agency itself would pay less than $29 million under EDAM, adding that "knowing exactly what Bonneville's portion of that is an … outstanding question, but knowing kind of where the maximum is for the BAA is helpful in providing a reference point."

By contrast, the $150 million Phase 2 costs associated with Markets+ would be financed, and BPA would repay its portion of the loan with a market transaction fee applied to each transaction made in the market. The $150 million covers staff, facilities, infrastructure, tools and applications.

BPA staff and stakeholders meet to discuss the agency's day-ahead market decision in Portland, Ore. on Jan. 29. | © *RTO Insider LLC*

> **Why This Matters**
>
> Upfront and annual fees are yet another factor BPA will consider as it moves toward a decision between Markets+ and EDAM.

BPA would pay its share of the Phase 2 funding fees on top of annual operating costs, which are projected to be between $13 million and $15 million, according to the staff's presentation.

Still, Laura Trolese with The Energy Authority noted that BPA would pay Phase 2 funding fees on market transactions over several years, which could potentially limit the financial impact.

Spencer Gray, executive director of the Northwest & Intermountain Power Producers Coalition, asked whether BPA would still be on the hook for its share of the Phase 2 portion if the agency decides to leave Markets+ after signing a Phase 2 agreement.

BPA Chief Business Transformation Officer Nita Zimmerman responded that it "gets into the specifics of the funding agreement. That's up to SPP to share and not me. It really depends on how far the funding agreements go as to how much we would be on the hook for and at what point."

Likewise, BPA could not provide a definite answer to what extent the fee agreements factor in "inflationary assumptions," following a question by Stefanie Johnson, strategic adviser at Seattle City Light.

There are still details, like specific amounts, timing and mechanics, that BPA needs to iron out before it can give stakeholders a clearer picture of how implementation fees would impact the agency under either Markets+ or EDAM. The agency is also working on estimates for internal implementation costs, staff said.

BPA has said it will issue a draft day-ahead market decision in March and a final decision in May. ■

CAISO/West News

WEIM Q4 Benefits Exceed $374M

Cumulative Benefits from CAISO's Real-time Market Reach $6.62B

By Robert Mullin

CAISO's Western Energy Imbalance Market (WEIM) provided participants $374.25 million in benefits during the fourth quarter of 2024, down about 4% from the same period a year earlier, according to an ISO *report* released Jan. 30.

Cumulative benefits since the 2014 launch of the WEIM grew by 31% in 2024, to $6.62 billion. Last year saw no new participants join the market, which includes balancing authority areas accounting for 80% of load in the Western Interconnection.

NV Energy earned the largest share of benefits at $73.08 million, followed by the Balancing Authority of Northern California ($57.99 million), PacifiCorp ($46.58 million) and Los Angeles Department of Water and Power ($34.21 million).

CAISO's benefits fell by half to $12.65 million, and the ISO was by far the market's largest exporter (1,060,806 MWh) and importer (877,127 MWh). PacifiCorp came in second in both categories, with its East and West BAAs exporting a combined 839,781 MWh and importing 540,163 MWh.

The ISO was also the location of the largest volume of wheel-throughs (814,970 MWh), followed by the Western Area Power Administration-Desert Southwest region (401,898 MWh) and Arizona Public Service (356,176 MWh). WEIM members gain no financial benefit from facilitating wheel-throughs, with only the sink and source benefiting.

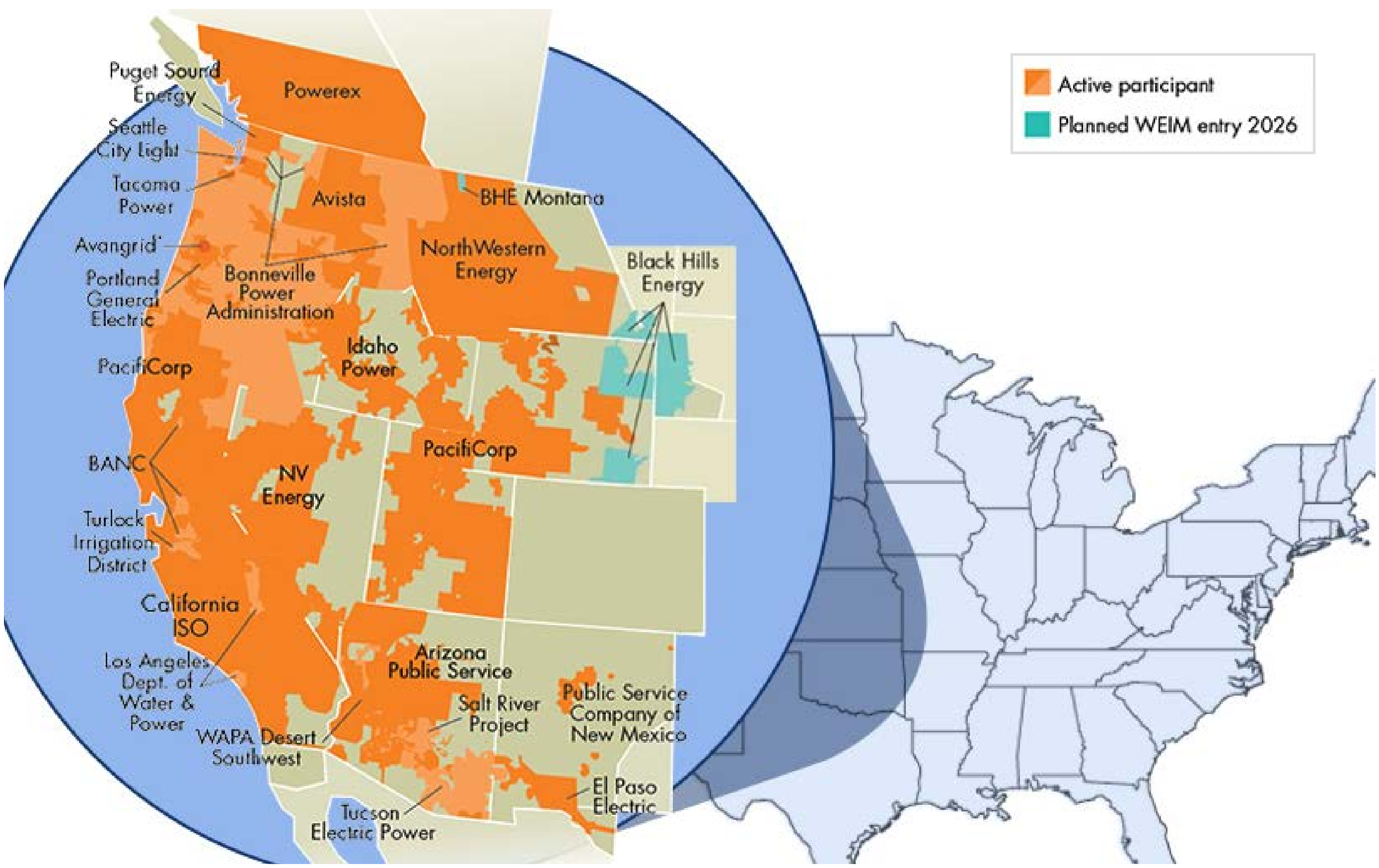
Vancouver, Canada-based Powerex earned the smallest share of benefits, at $840,000, down 98% year-over year. The company's imports fell by 73%, to 336,184 MWh, while its exports rose 25-fold to 16,902 MWh. Powerex will withdraw from the WEIM after confirming last month that it plans to join SPP's Markets+, although no date for the changeover has been announced. (See *Powerex Commits to Funding, Joining SPP's Markets+*.)

The report said WEIM operations prevented curtailment of 30,462 MWh of renewable generation during the fourth quarter, helping to avoid the emission of 13,038 metric tons of CO_2. The ISO estimates the market has been responsible for reducing carbon emissions by 1,043,034 MT since tracking began in 2015.

In a press release accompanying the report, CAISO said the benefits "emphasize the value of the ISO's *Extended Day-Ahead Market (EDAM)*, which promises to further build upon the benefits of WEIM for participants in the day-ahead market, where the vast majority of energy trading occurs."

The ISO expects to launch the EDAM in 2026 and noted that WEIM members PacifiCorp and Portland General Electric have already begun onboarding activities to participate in that market.

The WEIM currently has 22 participants, including the ISO, but it is likely to eventually lose a portion of those to Markets+, which SPP plans to launch in 2027. ■



CAISO was both the largest exporter and importer in the WEIM during Q4 2024. | *CAISO*

CAISO/West News

Brattle Study Shows Big Benefits for Calif. in 'Expanded' EDAM

State's Ratepayers Could Earn $790M More in West-wide EDAM than Limited Market

By Robert Mullin

California ratepayers would save millions more in a CAISO Extended Day-Ahead Market (EDAM) encompassing nearly all the West than in one that includes only those utilities likely to join the market, according to a new Brattle Group study.

The *study*, which was commissioned by the California Energy Commission, covers nearly every utility in the state — except the Imperial Irrigation District (IID) — and not just members of CAISO, whose balancing authority areas accounts for about 80% of the state's electricity load. It represents yet another in a series of Brattle — and other — production cost model studies published during the increasingly contentious competition between EDAM and SPP's Markets+.

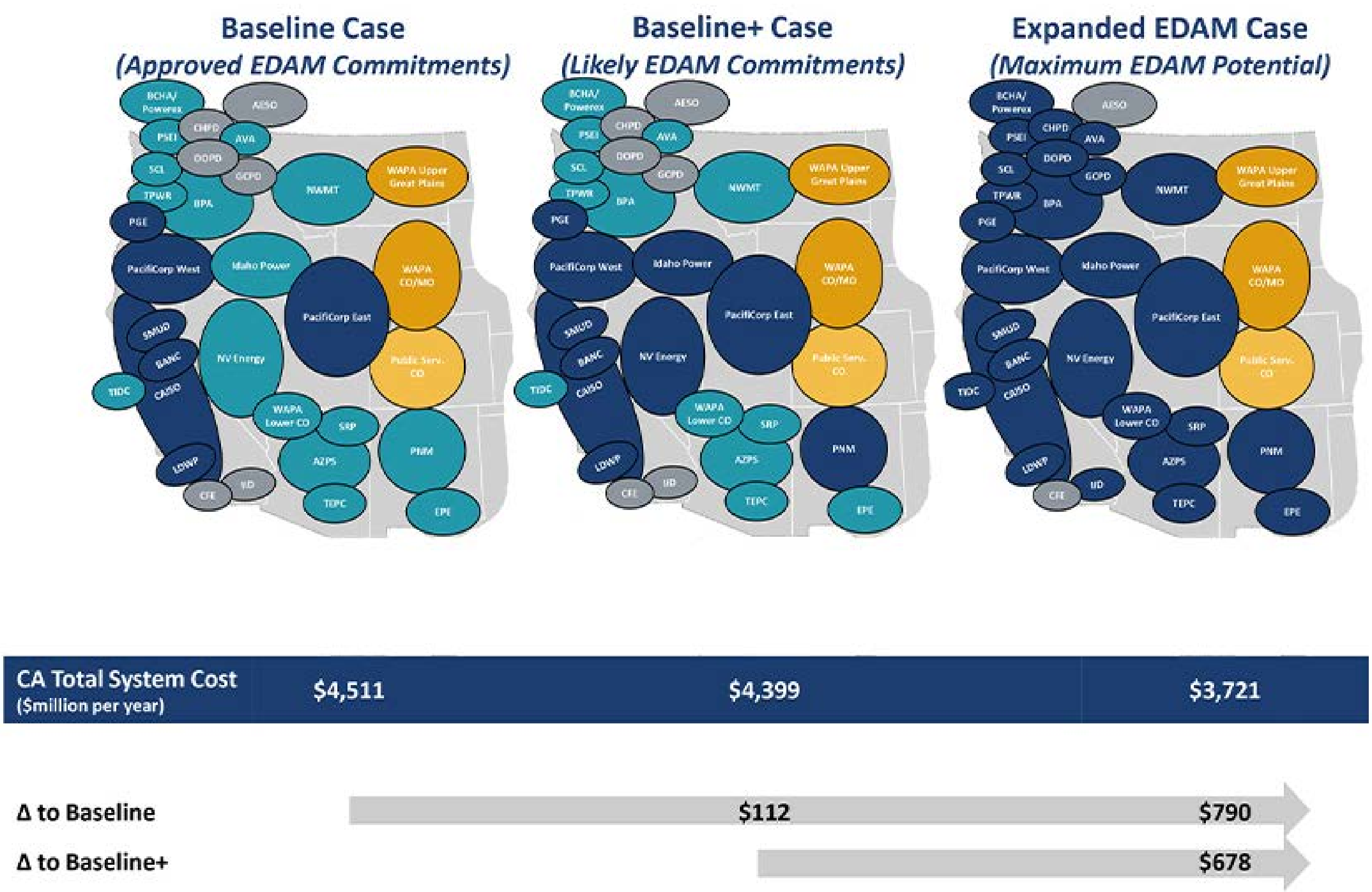
Why This Matters

The Brattle study shows what California electricity customers could possibly gain from allowing their state to relinquish some control over CAISO's markets.

Brattle Principal John Tsoukalis presented "preliminary" findings from the study during a Jan. 24 CEC workshop that examined the potential impact on California from the West-Wide Governance Pathway's "Step 2" plan to establish an independent "regional organization" (RO) to oversee CAISO's EDAM and Western Energy Imbalance Market (WEIM).

"A larger market means a larger and more diverse pool of transmission and generation resources," Tsoukalis said. "And what that means is … the market is able to more effectively shift from less efficient resources to more efficient resources. It finds the lowest-cost resource that can serve load in every given hour, and that leads to production cost savings for customers."

The study differs from previous Brattle studies in that the "Baseline" case is not the status quo — that is, the current arrangement before the launch of EDAM or Markets+ — but assumes a scenario in which EDAM is already operating but includes only CAISO and those entities that have already formally committed to that market. Those entities include PacifiCorp; Portland General Electric; Balancing Authority of Northern California (BANC) and its largest



The Brattle Group's study found California ratepayers will by far realize the greatest benefits from the largest EDAM footprint. | *The Brattle Group*

CAISO/West News

member, Sacramento Municipal Utility District; and Los Angeles Department of Water and Power (LADWP).

Under Brattle's "Baseline" case, California's estimated total system cost is $4.511 billion a year.

That figure drops by $112 million (to $4.399 billion) under a "Baseline+" case in which EDAM also consists of entities likely to join the market, which includes Idaho Power, NV Energy and Public Service Company of New Mexico.

But the biggest savings for California by far are found in the "Expanded EDAM" case, in which the CAISO market includes nearly every Western BA except for Western Area Power Administration entities already engaged with SPP markets, Public Service Company of Colorado (PSCo) and IID. In that scenario, Golden State ratepayers save $790 million annually compared with the "Baseline" case.

"Intermediate EDAM footprints [are] likely to produce benefits between the Baseline+ and Expanded EDAM 'bookend,'" according to a slide from the Brattle presentation.

But California would likely see significantly lower benefits than the top end — $182 million — in what will be the most likely outcome in the West — the "Split Market" case, where Markets+ consists of Powerex, the Bonneville Power Administration and most Washington utilities, NorthWestern Energy, PSCo, Arizona's utilities and El Paso Electric.

"The only difference between the Baseline+ case and the Split Market case is that we have Markets+ forming in that Split Market case, and what we see is there is a slight benefit, actually, to California customers from Markets+ forming, but it is about $500 million less than the Expanded EDAM case," Tsoukalis said.

The study drew that conclusion based partly on the assumption of a "relatively efficient seam" between EDAM and Markets+, an improvement over the current bilateral day-ahead market that would provide California customers with "increased access to low-cost resources in the Markets+ footprint."

Tsoukalis noted also that the study's day-ahead market benefit estimates are likely "conservatively low," just as previous studies had underestimated the actual benefits from the WEIM.

Emissions, Reliability Benefits

Brattle's study also shows significant carbon emissions benefits for California in the Expanded EDAM, with in-state gas generation falling by 31%, wind and solar curtailments falling by 10% and CO_2 emissions declining by 11.2% — though emissions in the rest of the West would increase 1.3%. Under the Split case, emissions in California fall by 3.5% and rise by 2.1% in the rest of the West.

The study also represents the first of the Brattle market studies that attempts to capture potential reliability benefits from the day-ahead market for all participants. To do that, it estimates the change in "market supply cushion," representing "the available generating capacity not committed to serving load" during each hour, which Tsoukalis said consists only of dispatchable resources and explicitly excludes hydro, wind and solar.

The study found that the supply cushion is about 25 GW higher in the Expanded than in the Split case.

"Focusing on the 10 tightest hours of the year, the supply cushion in the EDAM is 20,000 MW larger in the Expanded EDAM case than in the Split Market case (27.8% of load vs. 24% of load)," the study said.

Michael Wara, of Stanford University's Woods Institute for the Environment, who followed Tsoukalis' presentation with his own that showed the reliability benefits of Western grid regionalization, said he was "encouraged" to see Brattle's findings around reliability.

"I would have been surprised and a little depressed if their analysis, using a different method, said 'not much benefit,' but 25 GW of additional capacity is a substantial benefit on a hard day," he said. ■

CAISO/West News

Calif. Officials Propose New Safety Measures for Battery Storage

Moves Come After Massive Battery Fire at Moss Landing Site

By Elaine Goodman

California regulators have proposed new safety standards for battery energy storage systems following a series of incidents at the facilities, including a major fire Jan. 16 at Vistra's Moss Landing site.

The California Public Utilities Commission is proposing the standards as an update to General Order 167, which was first adopted in 2004 and sets safety standards for electric generating facilities. The commission is expected to consider the update, known as GO 167-C, during a March 13 voting meeting.

"Regulatory oversight of ESS [energy storage system] facilities is necessary because of the safety and reliability risks that can occur if ESS facilities are not properly operated and maintained," the CPUC said in a proposed resolution to adopt the standards.

In addition, a bill has been introduced in the California legislature addressing battery storage system safety. Assembly Bill 303 would restore local oversight for energy storage projects in the state, according to its author, Assemblymember Dawn Addis (D).

Under the CPUC's proposed standards, battery energy systems would face similar requirements to those of electric generating facilities.

For example, ESS owners would be required to file operation and maintenance plans with the CPUC, steps now required of generating asset owners. ESS owners also would be required to report safety-related incidents to the CPUC within 24 hours — just as generating asset owners must do now.

And in a new mandate for both energy storage and electric generation, facility owners would be required to work with local authorities to develop an emergency response and emergency action plan.

Why This Matters

The proposed safety measures could hinder California's efforts to reach 52,000 MW of battery capacity by 2045.

The changes are in response to direction from state lawmakers in Senate Bill 1383 of 2022 and SB 38 of 2023.

The CPUC held three workshops in 2024 to gather feedback while developing the proposed standards.

Battery Blazes

Battery storage is seen as key to meeting the state's clean energy goals. Batteries can store solar energy during the day and release it during peak demand in the evening.

California's battery energy storage capacity increased from 770 MW in 2019 to 13,391 MW in October 2024, with about 3 GW of that added since April 2024. (See California Hits Milestones for Batteries, DR Grid Support.)

That puts the state at about a quarter of its projected energy storage need of 52,000 MW by 2045.

But battery storage presents safety concerns. The worries were underscored Jan. 16, when a fire broke out at Vistra's 300-MW energy storage facility at Moss Landing in Monterey County. The lithium-ion battery facility is one of the world's largest battery energy storage systems.

The fire, which prompted the evacuations of 1,200 people, is now under investigation. Staff from the CPUC's Safety and Enforcement Division visited the site Jan. 22 as part of its probe.

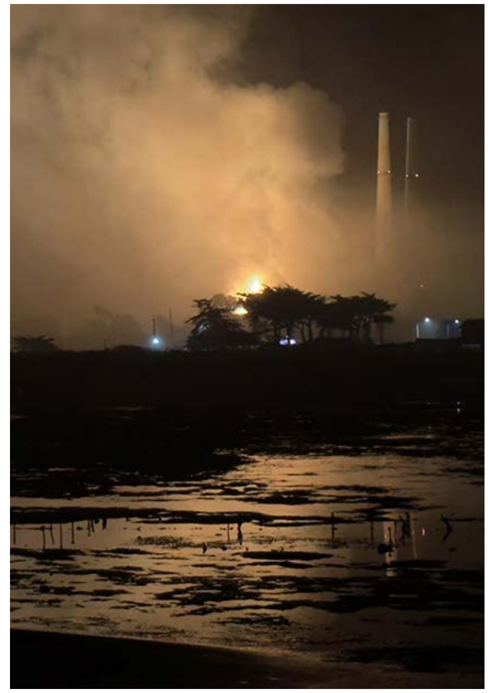
The CPUC listed nine other safety incidents at battery facilities since 2021, including four in 2024. In one incident in September 2024, a fire at a San Diego Gas and Electric battery storage facility in Escondido prompted evacuations.

Evacuations were also ordered in May 2024 during a fire at REV Renewables' Gateway Energy Storage facility in Otay Mesa.

Battery Safety Bill

AB 303 from Assemblymember Addis is also known as the Battery Energy Safety and Accountability Act.

The bill would prohibit battery energy systems of 200 MWh or more on an environmentally sensitive site or within 3,200 feet of a "sensitive receptor," such as a home, school or community center.



A fire broke out Jan. 16 at Vistra's Moss Landing battery energy storage facility. | *County of Monterey, Calif.*

The bill would also exclude battery storage projects from the California Energy Commission's opt-in certification process, a streamlined path to approval. (See 2 Huge Solar-plus-storage Projects Planned in California.)

Under the opt-in process, the CEC becomes the lead agency for permitting and state environmental review. The CEC certificate is in lieu of any permit that normally would be required through the local land-use review process and most state permits.

"AB 303 is a proactive measure that will ensure companies like Vistra go through the normal, local, regulatory process," Addis said in a statement. "It is designed to build trust, increase safety and give communities a choice by restoring local community processes for permitting these projects."

The California Energy Storage Alliance is opposed to the bill, saying it is "excessive and does nothing to enhance public safety."

"Instead, it creates unnecessary barriers to the deployment of critical energy storage systems needed to stabilize our grid and support California's transition to a clean energy future," CESA said in a release.

AB 303 is awaiting assignment to committee. ■

CAISO/West News

CPUC Approves Rules to Streamline New Transmission

Agency Says Changes Needed to Maintain Reliability, Meet Calif. Climate Goals

By Elaine Goodman

| © RTO Insider LLC

California regulators have approved rules to streamline permitting of transmission projects, saying the move is needed to maintain grid reliability and reach state climate goals.

The California Public Utilities Commission on Jan. 30 approved an update to its General Order 131-D, which pertains to permitting of transmission and distribution lines, generating facilities and substations.

The *decision* will speed up transmission project permitting while maintaining environmental safeguards, Commissioner John Reynolds said in a statement.

"Building a clean energy future requires getting renewable power to where it's needed most," he said. "We can't meet our climate goals without significantly expanding our transmission infrastructure."

The revised general order, now known as *GO 131-E*, takes a multipronged approach to permit streamlining.

Transmission developers must now meet with CPUC staff at least six months before submitting an application — a step that will "better prepare applicants and help the review process run more smoothly," the CPUC said in a release.

The order allows transmission developers to submit their own draft versions of California Environmental Quality Act (CEQA) documents with their applications. That cuts out a step in the previous set of rules, in which an applicant provided a proponent's environmental assessment (PEA), which was then followed by staff preparation of an environmental document.

The applicant's draft version of environmental documents will undergo CPUC review. Applicants still have the option to use the PEA process.

The revised order also includes a "rebuttable presumption" that a proposed project meets the CPUC requirement for need if CAISO has already determined the project is needed and approved it in a transmission plan. The CPUC said the change will avoid "duplicative need determinations and unnecessary alternatives analyses."

The rebuttable presumption provision arose from *Assembly Bill 1373* of 2023.

In addition, the CPUC plans to launch a pilot program to track CEQA review timelines and look for ways to further speed up the CEQA process for some transmission projects.

2-Phase Proceeding

The new rules the commission approved Jan. 30 are the second phase of changes to GO 131-D aimed at streamlining the transmission project permitting process. The proceeding, which was led by Commissioner Karen Douglas, is now closed.

"These changes will accelerate permitting timelines by reducing redundancy and shifting environmental analysis earlier in the application process," Douglas said in a statement.

In Phase I of the proceeding, GO 131-D was modified in response to *Senate Bill 529* of 2022. The bill changed the type of CPUC permit

Why This Matters

The new rules, which will speed up environmental reviews for transmission projects that California meet its climate goals, could accelerate transmission development in the state.

CAISO/West News

needed to expand a transmission facility from a Certificate of Public Convenience and Necessity (CPCN) to the simpler Permit to Construct (PTC). A permit exemption may also be requested. (See *CPUC Works to Revamp Tx Permitting Rules*.)

In general, a CPCN is needed for transmission projects of 200 kV or more, while a PTC is required for projects of between 50 and 200 kV.

SB 529 also allows developers to seek a PTC or exemption for transmission line extensions, upgrades or other modifications, even if the transmission line is more than 200 kV.

The commission approved the Phase I changes in December 2023.

Phase II of the proceeding added definitions for several of the Phase I terms, including transmission facility "expansion," "extension" and "upgrade."

"Expansion" is now defined as an increase in the width, capacity or capability of an existing electrical transmission facility, which may include rewiring or reconductoring to increase capacity, increasing the load carrying capacity of existing towers, or converting a single-circuit transmission line to a double-circuit line.

GO 131-E defines "extension" as an increase in the length of an existing transmission facility within existing transmission easements, rights-of-way or franchise agreements; or a generation tie-line (gen-tie) segment or substation loop-in.

Pilot Program

A new CPUC pilot program will evaluate the CEQA review process for transmission projects. It will include at least one application each from Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric.

Two projects will involve an Environmental Impact Report (EIR), and two others will use a less time-intensive Mitigated Negative Declaration process. Projects in the pilot study will be a mix of those competitively and noncompetitively bid.

Results will be reported every other year starting Dec. 1, 2026.

Some stakeholders were opposed to the pilot program. PG&E and SDG&E said CPUC resources would be better spent on speeding review of projects now in the pipeline. The Center for Energy Efficiency and Renewable Technologies called the pilot program a step backward, saying mandatory deadlines to complete a CEQA review should be set instead.

The commission's decision noted that the CPUC already routinely reviews its CEQA processes and looks for ways to improve efficiency.

"Therefore, running a pilot aligns with current commission practice," the decision stated. "As such, it should not distract the commission from meeting its commitment to expedite the permitting of projects." ■

ERCOT News

765-kV Lines in West Texas Inch Closer to Reality

By Tom Kleckner

The drive to build 765-kV lines in Texas continues to inch forward, with ERCOT and stakeholders working to provide enough information for regulators to reach a decision on which framework to go with by May 1.

During a workshop on extra-high-voltage (EHV) transmission Jan. 27, ERCOT staff shared with stakeholders their "traditional" 345-kV portfolio of projects as part of the grid operator's annual *Regional Transmission Plan* (RTP). They also included for the first time a 765-kV study, a result of their *2024 Permian Basin Reliability Plan* identifying transmission facilities and import paths needed to serve existing and future demand in petroleum-rich West Texas.

The Texas Public Utility Commission in September approved the Permian Basin plan, which included both 345-kV and 765-kV infrastructure, and $13 billion to $15 billion in initial investment. However, it deferred a decision on the import paths' voltage levels to no later than May 1, 2025. (See *Texas PUC Approves Permian Reliability Plan*.)

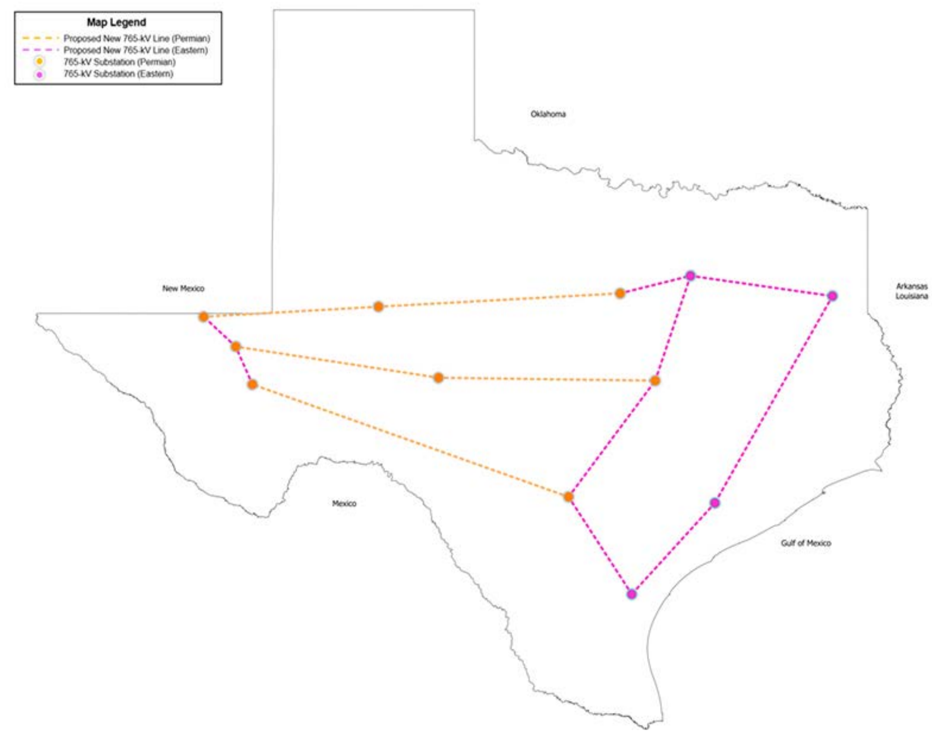
The commission plans to open a comment period following a Jan. 31 discussion of the two plans. The PUC will host its own EHV workshop March 7 (*55718*).

"My understanding from working with commission staff is that's just the beginning of the process," Prabhu Gnanam, ERCOT's director of grid planning, told the workshop's attendees. "All of this to help set up the commissioners to be able to make a decision before May 1."

Either plan will require thousands of miles of transmission lines to be built through 2030. Both will cost more than $30 billion, according to initial projections, far surpassing the last project of its kind in Texas, the Competitive Renewable Energy Zone (CREZ) initiative completed in 2014. That project resulted in 3,600 miles of transmission lines, built at a cost of $6.9 billion. CREZ has freed up more than 23 GW of wind capacity in West Texas that since has been added to the grid.

The Texas 765-kV Strategic Transmission Expansion Plan (STEP) has an estimated construction cost of $32.99 billion and includes:

- 2,468 miles of 765-kV lines.
- 649 miles of new 345-kV lines and 1,098 miles of existing 345-kV upgrades.
- 324 miles of new 138-kV lines and 1,287 miles of existing 138-kV upgrades.
- 446 miles of existing 69-to-138-kV conversions.



765-kV Core Plan needed in 2030 | *ERCOT*

The 2024 RTP 345-kV plan has a projected construction cost of $30.75 billion and includes:

- 2,673 miles of new 345-kV lines and 1,913 miles of existing 345-kV upgrades.
- 334 miles of new 138-kV lines and 1,714 miles of existing 138-kV upgrades.
- 647 miles of existing 69-kV to 138-kV conversions.

Both plans will require an estimated $5 billion annually over the six-year planning horizon, as compared to an average of $3 billion per year over 2022/24, the grid operator said.

ERCOT says its analysis indicates the 765-kV STEP would provide "significant economic and reliability benefits" to the system because 765-kV lines are more efficient in moving power from resource-rich regional to load centers over long distances.

The grid operator said last year it expects over 150 GW of demand, more than its current capacity, to be added to the system by 2030. Almost 50 GW of that expected demand is from the oil and gas natural load, AI and data centers, cryptocurrency mining, electrification, and hydrogen processing and related infrastructure.

"If those large loads move from one county to the next, you're still making that power flow across the state," Kristi Hobbs, ERCOT's vice president of system planning and weatherization, told the workshop's attendees. "Then you can deal with any changes to the large loads through the subsequent underlying 345-kV network that will support it."

Staff conducted steady-state transfer capability, dynamic stability and system strength analyses to gain a clearer picture of how either option could support reliability and grid stability. Staff said the higher-voltage option would reduce congestion costs by $229 million

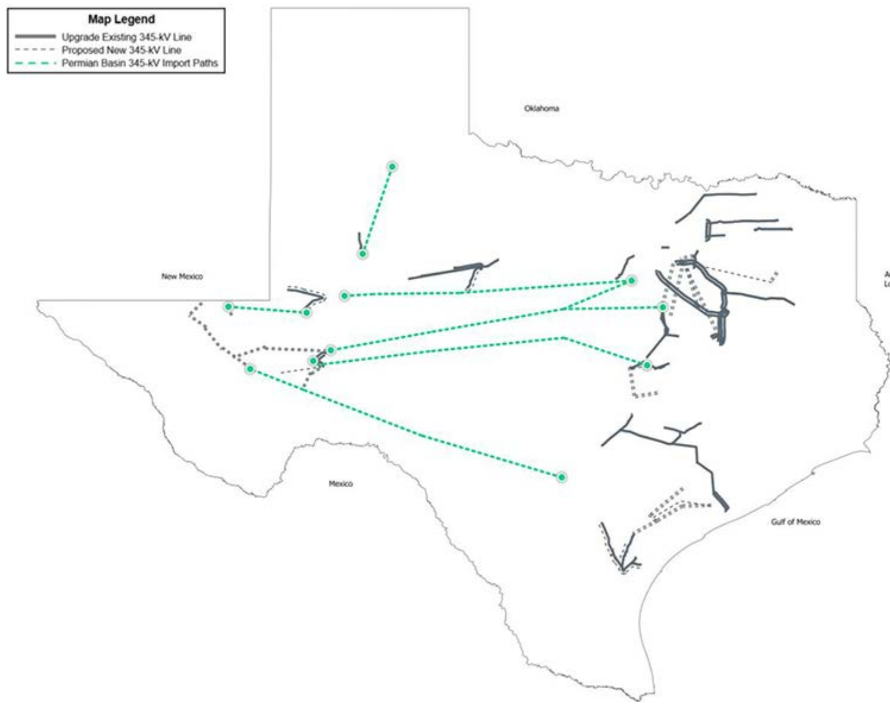
ERCOT News

annually and cut system production costs by $28 million, both annually. (ERCOT has incurred $4.27 billion in congestion costs the past two years.)

The 765-kV STEP would reduce energy losses by 560 GWh each year, equivalent to a 128-MW thermal unit operating at a 50% capacity factor, staff said in its report. It also would yield an increase of up to 3,000 MW in power transfer capability and a 13% stability limit in West Texas.

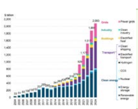
ERCOT used $6.2 million/mile and $4.2 million/mile as "generic cost estimates" for the 765-kV and 345-kV facilities. The 765-kV cost estimate is based on the same dollar figure used in MISO's Long-range Transmission Plan, approved in December and including 1,800 miles of new 765-kV projects. The 345-kV number is based on the average cost for new 345-kV lines provided by transmission service providers in the Permian Basin study.

"As we look at the additional transfer capability of the higher-voltage network, which also would be setting us up for future growth as well and giving us some breathing room ... the TSPs and stakeholders that try to take outages on the system today can tell you that we have maximized or optimized the use of our current system," Hobbs said. ■



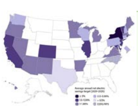
New 345-kV lines and upgrades as part of the 345-kV plan. | *ERCOT*

National/Federal news from our other channels



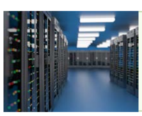
Global 2024 Energy Transition Investments Estimated at over $2T

NetZero Insider



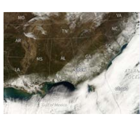
ACEEE Report Highlights Success of 'Next Generation' Efficiency Policies

NetZero Insider



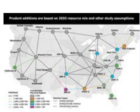
Chevron, Engine No. 1 to Power Data Centers

NetZero Insider



FERC, NERC Praise Grid Performance in Cold Snap

ERO Insider



Texas RE Calls ITCS Recommendations 'Very High Level'

ERO Insider

FERC Upholds $150K Penalty for Facility Misratings

ERO Insider

RTO Insider subscribers have access to two stories each month from *NetZero* and *ERO Insider*.

ERCOT News

Texas PUC Begins Registering Crypto Mining Facilities

The Texas Public Utility Commission has opened an online portal on its website to accept registrations from cryptocurrency mining facilities.

The PUC said Jan. 27 that facilities with a demand of more than 75 MW are required to register by Feb. 1. Future facilities must register no later than one working day after receiving retail service, it said. Crypto miners registered with the commission must provide information annually about the facility's location, ownership and electricity demand.

Those facilities failing to register could face fines of $25,000 per violation per day.

The PUC in November adopted a new rule mandated by state law that requires crypto miners in ERCOT's region to register. (See "New Rules for Crypto Miners," *ERCOT to Recommend RMR Agreement for Braunig*).

ERCOT labels cryptocurrency facilities as "flexible loads" because of their ability to quickly adjust their power consumption in response to increasing demand or prices. The facilities often are compensated for shutting down their consumption; Riot Platforms in August 2023 earned $31.7 million for curtailing demand, almost four times the amount it made from producing bitcoin.

The Texas grid operator said in 2024 that it expects demand to nearly double in six years, from 85 GW to as much as 150 GW by 2030, due to cryptocurrency mining, data centers and artificial intelligence.

ERCOT Cancels MRA Request for Braunig 1, 2

ERCOT said Jan. 28 it is canceling a request for more cost-efficient must-run alternatives for two aging gas plants that it says are needed to support grid reliability.

The gird operator said it did not receive any eligible proposals that were more cost-effective than contracting for mobile generators leased by CenterPoint Energy to avoid committing CPS Energy's Braunig Units 1 and 2 under a reliability must-run (RMR) contract.

ERCOT's Board of Directors in December directed staff to develop an RMR agreement with CPS Energy, San Antonio's municipality, to return Braunig 3 to service into 2027. (See "ERCOT to Pursue Braunig MRAs," *Texas PUC Shelves PCM Design Over Lack of Benefits*.)

CPS Energy told ERCOT in 2024 that it intended to retire all three 1960-era units in March 2025.

ERCOT said it expects further discussion on the issue during the Feb. 3-4 board of directors meeting. The ISO also said it expects to provide a recommendation during a future special board meeting over whether to commit Braunig Units 1 and 2 through an RMR agreement or move forward with the mobile generation solution.

CPS Energy has told ERCOT the Braunig units' standby costs are:

- $2,382/hour for one year, $1,500/hour for two years (Braunig 1).
- $2,558/hour for one year, $1,597/hour for two years (Braunig 2).
- $3,599/hour for one year, $2,246/hour for two years (Braunig 3). ■

— Tom Kleckner

Riot Platform's Rockdale Facility near Austin has a load of 700 MW. | *Riot Platform*

ISO-NE News

New England Gas Generation Hit a Record High in 2024

By Jon Lamson

As overall power production ticked up in New England in 2024, natural gas generation reached its highest annual total in the region's history, accounting for over 55% of all generation and 51% of net energy for load, according to *new data* from ISO-NE.

Natural gas generation provided 59,883 GWh of power in 2024, up from 55,585 in 2023, which resulted in an *increase* in annual power sector emissions. Oil generation remained steady year-over-year, while coal generation accounted for 234 GWh, a small increase relative to 2023.

One of the largest year-over-year changes came from a major reduction in power imported from Canada, as a massive *drought* caused Hydro-Québec to reduce its exports. Net imports from Canada declined for the second straight year, dropping to 6,067 GWh, less than half of the 2023 levels.

For renewables, solar and wind generation both increased in 2024 compared to 2023, but they remain a relatively small part of the region's resource mix. Solar increased from 3,852 GWh in 2023 to 4,554 GWh, while wind increased from 3,302 GWh to 3,517 GWh. This does not include power from behind-the-meter solar, which reduced net load by about 4,300 GWh in 2023.

While solar has grown steadily over the past 10 years, wind power production has been largely stagnant since 2017. Despite the year-over-year increase, wind was lower in 2024 compared to 2019-2022. This could change rapidly if Vineyard Wind 1 and Revolution Wind ramp up power production in 2025 and 2026.

Nuclear generation rebounded in 2024 after a significant down year in 2023. It has remained relatively consistent around 26,000 GWh of annual generation after the closure of the Pilgrim Nuclear Power Station in 2019.

The decrease in imports, coupled with the spike in gas generation, contributed to the highest annual generation total in the region since 2013. The peak load in 2024 was 24,871 MW, up 828 MW from 2023 but in line with the region's average annual peak over the past 10 years.

Both the peak load and total annual generation remain well below the highs reached in the mid-2000s. The region hit its all-time peak in 2006 at 28,130 MW, while total generation peaked at 131,877 GWh in 2005.

In the coming years, ISO-NE's peak load and overall generation requirements are projected to exponentially increase with heating and transportation electrification. The RTO projects the peak load to increase by about 10% by 2033, coupled with a 17% increase in electricity consumption. (See *ISO-NE Predicts 10% Increase in Peak Demand by 2033*.)

These increases will likely accelerate in the years prior to 2050. ISO-NE projected in its Economic Planning for the Clean Energy Transition *study* that the region's peak load will reach 60.8 GW by 2050. Massachusetts' 2050 Decarbonization Study projected a more modest 57 GW.

As demand increases, the states will need to find a way to reverse the increase in gas generation to meet their climate goals for 2030 and beyond. ISO-NE has expressed interest in establishing new market mechanisms to support low-carbon resources and dispatchable resources, but the states have been slow to pursue these options.

Beyond emissions concerns, there are physical constraints to how much more gas generation the region could add to meet rising demand, particularly during the winter. Gas utilities reserve much of the pipeline capacity into the region in the winter to meet heating needs, limiting gas generation during these periods.

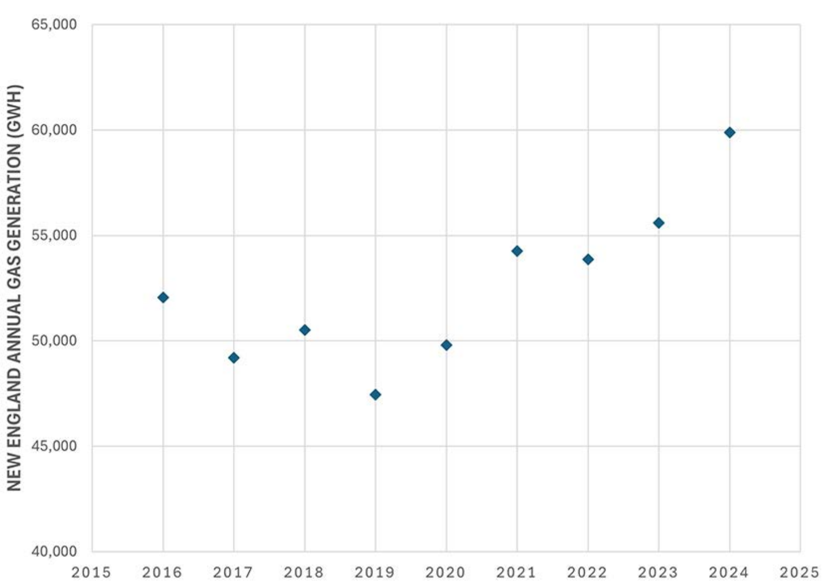
In 2023, Enbridge proposed a significant pipeline expansion project, intended to help ease some of the region's gas constraints. The company marketed the project to meet growing demand from generation and local distribution companies. (See *Enbridge Announces Project to Increase Northeast Pipeline Capacity*.)

It has not filed the project with FERC, and it told a municipal utility in May that it is "looking to get signatures on the precedent agreements, and at that point, we will file with [FERC]."

However, Enbridge and the gas utilities could face a challenging regulatory environment to approve contracts for the project in Massachusetts, where regulators are pushing the utilities to transition away from natural gas in accordance with the state's decarbonization requirements. ■

Why This Matters

While New England's reliance on natural gas for generation hit its all-time high in 2024, the region continues to face significant gas constraints in the winter, while long-term reliance on natural gas is likely incompatible with state decarbonization goals.



New England annual gas generation (GWh) | © *RTO Insider LLC*

ISO-NE News

NEPOOL TC Votes Against Compliance Proposal for Interconnection Order

By Jon Lamson

The NEPOOL Transmission Committee has declined to support a compliance proposal from the New England transmission owners for a recent FERC order preventing the TOs from charging interconnection customers for operations and maintenance fees associated with network upgrades.

In December, FERC sided with clean energy advocacy group RENEW Northeast in a dispute over who must pay for the upkeep and operation of interconnection network upgrades. The commission determined these costs should not be paid by the interconnection customer, shifting them over to transmission rates. (See *FERC Sides with New England Developers on Interconnection Complaint.*)

In response to the order, the TOs propose to amend the RTO's tariff to remove operations and maintenance costs from network upgrade requirements.

However, RENEW argues the TOs' proposal does not "remove all the annual costs associated with network upgrades, stand-alone network upgrades and distribution upgrades as required by the order."

RENEW wrote that the TOs' proposal fails to address "some remaining annual costs … such as cost of capital, federal and state income taxes, and other related costs," which still could be assigned to interconnection customers, it wrote in a *memo* published prior to the Jan. 29 TC meeting.

The group also argued that provisions of the TOs' proposal that assign "repair and replacement" costs to interconnection customers are "directly contrary to the requirements" of the Dec. 19 order.

Finally, RENEW opposed the proposal to continue billing operations and maintenance costs until the TOs recalculate their billing formulas, and to issue refunds for these charges by mid-June. The group argued that continuing these charges is prohibited by the order.

The TOs' proposal failed to pass with just *33.3% support* from the committee, backed by members of the transmission and publicly owned entity sectors. Members of the generation, alternative resources, supplier and end user sectors opposed the proposal. It now will head to the Participants Committee in February for a vote, without the backing of the TC.

| © RTO Insider LLC

Also at the Jan. 29 meeting, the TC voted to support a Transmission Operating Agreement for the New England Clean Energy Connect transmission line and *discussed compliance* with FERC Order 904.

Order 904, released in November 2024, prohibits transmission providers from including charges in transmission rates to compensate generators for reactive power which falls "within the standard power factor range by generating facilities."

The committee also discussed *improvements* to the ISO-NE's economic study process. ISO-NE economic studies are intended to evaluate and address potential market inefficiencies or transmission congestion or integrate new resources or load.

The RTO is in the second phase of a project to improve these studies, which is focused on making changes to identify "system efficiency issues and needs by establishing a clear trigger for when to issue a request for proposals, defining benefit metrics for evaluating RFP responses and streamlining the RFP process into a single stage."

Patrick Boughan of ISO-NE noted that the RTO plans "an interregional model that explicitly models the projected future demand and resources of surrounding regions," instead of relying on historical data, as it has done in the past. The RTO also plans to transition from modeling imports as zero-cost resources to estimating their cost based on the interregional model.

Boughan also said ISO-NE "does not propose to pursue consideration of capacity savings" in the Phase 2 project, noting the RTO simultaneously is developing a major overhaul of its capacity market and has "no reliable method to estimate capacity savings" over the 10-year planning horizon.

He also noted the RTO plans to mirror how its longer-term transmission planning process treats aging transmission equipment.

"If a proposal includes rebuilding or eliminating a transmission element that is on the *Asset Condition List*, or an element that is more than 40 years old, the avoided cost of that upgrade will be counted as an avoided transmission investment," Boughan said. ■

ISO-NE News

Massachusetts DPU Approves Price Increase for NECEC Line

By Jon Lamson

The Massachusetts Department of Public Utilities approved a settlement agreement for the New England Clean Energy Connect (NECEC) transmission line Jan. 27, authorizing a significant cost increase to account for regulatory delays to the project.

The agreement comes after political and regulatory obstacles caused an approximately two-year pause in the line's construction. Massachusetts ratepayers will now be on the hook for a price increase estimated to total $521 million in 2017 dollars, which equates to about $670 million (*24-160*).

When in service, the 1,200-MW NECEC project will facilitate power flow from Quebec to New England. The project was selected by Massachusetts in a 2018 clean energy solicitation and is being developed by a subsidiary of Avangrid.

While the project is now fully permitted and under construction, opposition to the line in Maine brought together an unlikely pairing of fossil fuel generators and environmental nonprofits, including the Sierra Club and the Natural Resources Council of Maine.

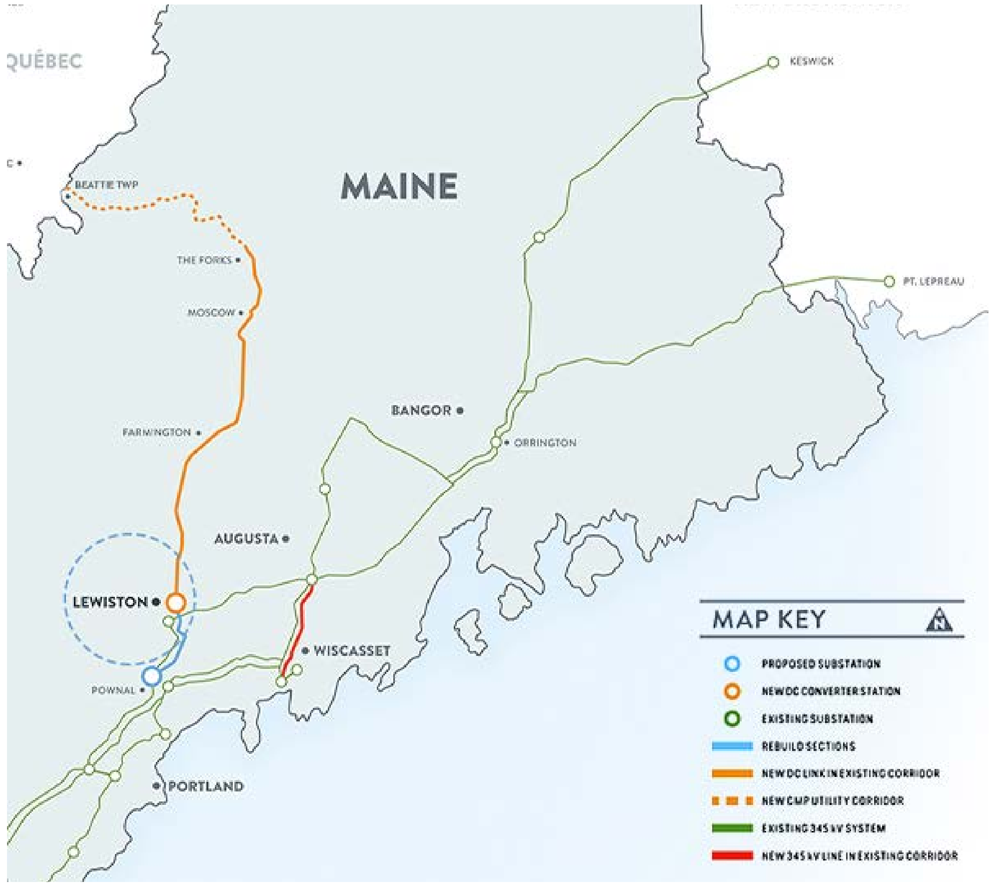
This coalition succeeded in getting a *ballot referendum* passed in 2021 to stop the project, but it was eventually struck down by the Maine Supreme Judicial Court. Construction on the project resumed in August 2023.

While NECEC was initially projected to come online in late 2022, it is now on track to be in service by the end of this year, according to a January progress report. The developer wrote that the HVDC line is fully cleared, with 919 pole bases set, 756 poles erected and wires installed on 554 poles.

Negotiations on the settlement agreement included the utilities, the developer, the Massachusetts Attorney General's Office and the state's Department of Energy Resources. The utilities filed the agreement in October 2024.

Why This Matters

The project delays, attributed to well funded political opposition efforts, are set to cost ratepayers hundreds of millions of dollars and may serve as a cautionary example for future transmission projects in the region.



NECEC project map | *Avangrid*

The DPU ruled that "the distribution companies and the other settling parties provided testimony and significant evidence" that the cost increases were caused by delays stemming from the Maine referendum.

"The incremental cost increase negotiated by the settling parties is less than the costs NECEC claims to have incurred due to the Maine initiative," the department noted. It highlighted the utilities' findings that the project would still provide about $3.38 billion in net benefits, calculated in 2017 dollars.

The DPU wrote that it expects the project to save customers an average of $18 to $20 per year and cut emissions by about $2 million tons annually for the length of the contract.

The settlement agreement will increase the monthly transmission charges to the distribution companies for the first year of the contract from $9.29 to $13.61/kW-month. These charges will grow to $19.82/kW-month by the final year of the contract.

"NECEC is essential to our shared clean energy goals," DPU Chair James Van Nostrand said in a *statement*. "The project will not only provide renewable energy year-round, but most importantly, it will stabilize electric rates throughout the state, saving ratepayers money over time."

ISO-NE studies have shown that the project would bring significant reliability benefits to New England. In a 2024 *study*, the RTO found that the line would cut energy shortfall by 31 to 36% in a worst-case 21-day winter scenario, preventing about 80,000 MWh of shortfall.

Avangrid also has an ongoing lawsuit against NextEra Energy, alleging it broke state and federal antitrust laws in its efforts to stop the project and caused damages of at least $350 million. NextEra owns several generators in the region that would likely be affected by the lower energy prices enabled by NECEC (*3:24-cv-30141*). (See *Avangrid Sues NextEra over 'Scorched-earth Scheme' to Stop NECEC*.) ■

MISO News

FERC Approves Annual Megawatt Cap for MISO Interconnection Queue

By Amanda Durish Cook

FERC has given MISO an all-clear to cap project hopefuls lining up for its overflowing generator interconnection queue at 50% of the RTO's peak load.

FERC said MISO's plan to impose a yearly cap of 50% of the non-coincident peak per study region is fair considering the footprint's 309-GW, backlogged interconnection queue (*ER25-507*). The commission said in the Jan. 30 order that the cap "will allow MISO to conduct its study cycles more effectively … which will ultimately benefit interconnection customers."

The megawatt cap would take effect beginning with the grid operator's 2025 cycle of queue submissions.

MISO late last year made a second attempt to instate a megawatt cap on its annual queue cycles after FERC rejected MISO's first attempt based on concerns over too many cap exemptions, the formula to establish the cap being unrealistic and potential resource adequacy deficits from limiting new generation onto the grid. (See *MISO Queue MW Cap to be Filed Sans Regulator Exemption for RA Generation Projects* and *MISO Stakeholders Debate Usefulness of MW Queue Cap Pending Before FERC*.)

With the cap in place, MISO said it will reopen acceptance of a new queue cycle at the end of this year. MISO had paused processing new queue cycles for more than a year and skipped a 2024 cycle altogether. (See related story *MISO Unveils Later Timeline for Queue Processing Restart*.)

MISO said a jump in interconnection requests beginning in 2020 has made it nearly impossible to create accurate models to study the new interconnections.

It fielded 52.4 GW of requests in 2020, 76.8 GW in 2021, and 170.8 GW in 2022. The queue currently contains nearly 1,700 interconnection requests totaling about 309 GW. By comparison, MISO's peak load holds at about 127 GW, and the footprint boasts a total 191 GW of functioning installed capacity.

FERC agreed with MISO that "the large number of interconnection requests submitted into MISO's interconnection queue would cause MISO to make unrealistic modeling assumptions, producing study results with inaccurate network upgrade cost estimates."

"Such inaccuracies, in turn, would drive withdrawals from the queue, further affecting study results and causing delays," FERC wrote.

The commission said MISO's 50% methodology is reasonable based on MISO's explanation that it represents a cliff before studies begin showing that major transmission upgrades are necessary, which is "typically indicative of voltage collapse." FERC also said MISO this time explained how the cap still would allow sufficient generation capacity to be developed to meet resource adequacy standards.

MISO has said that even with a cap in place, it could achieve a total 310-GW queue throughput through 2042.

"We agree with MISO that the proposed queue cap formula strikes a reasonable balance between limiting the volume of requests to a level that can be processed efficiently and avoiding unnecessary barriers to entry that will delay the development of the generation capacity needed to meet growing supply shortages within the MISO region," FERC said.

FERC decided MISO's thinning of cap exemptions was appropriate and took care of concerns that MISO would have "unbounded" exceptions to the cap. It disagreed with MISO South regulators that removal of an exemption for projects deemed necessities by state public service commissions treads on states' authority. FERC said if a public utility wants to modify its generator interconnection procedures on file, it must file with FERC.

Exemptions to the cap now are limited to generators with provisional generator interconnection agreements; generators seeking to replace retiring counterparts and in need of extra interconnection service; and those generators wanting to convert their unguaranteed energy resource interconnection service with the higher-quality network resource interconnection service.

FERC dismissed clean energy groups' concerns that the cap method doesn't feature a "first-ready, first-served" approach for generation projects. The commission said projects entering the queue still must meet MISO's commercial readiness requirements to advance into the queue. It also said MISO's recently raised fees, automatic withdraw penalties and requirements that developers show proof they secured land should winnow out speculative projects. FERC declined to consider Shell Energy's recommendation that MISO impose a per-developer limit on project submission based on similar reasoning.

FERC also rejected some stakeholders' arguments that the cap isn't reasonable because it didn't resemble approved caps like CAISO's and wasn't limited to a specific amount of time like SPP's. It said it wouldn't go down the road of deciding whether the cap was "more or less reasonable" than other possible rate designs.

"MISO, CAISO and SPP have chosen to address interconnection queue management problems caused by an overwhelming number of interconnection requests through different approaches based, in part, on regional needs and characteristics," the commission said, while pointing out that MISO has committed to reviewing the effectiveness at the cap in about three years.

The commission refused utilities and MISO South regulators' recommendation that FERC tie approval of the cap to a resource adequacy express lane MISO is working to build into the queue, saying the future filing is a separate issue and not yet up for consideration. (See *Generation Developers Ask for Scoring System on MISO Queue Fast Track*.)

However, Chair Mark Christie wrote separately to encourage MISO to try again at developing exceptions to the cap for generation facilities that are labelled indispensable to resource adequacy by public service commissions. He said FERC "wrongly" rejected exemptions for state-designated generators in MISO's first filing.

Christie said he was "disappointed in MISO's failure to include a state exemption in its second filing, as the membership of the commission has changed significantly since last January and already has shown much more acknowledgement of the critically important role played by state utility regulators in ensuring reliable power to their states' consumers."

"MISO should have stuck to its guns and vigorously restated its reasons for including a state exemption," Christie wrote.

While FERC said it was in favor of MISO's cap, it encouraged the RTO to "continue considering other avenues to manage its interconnection queue" and said MISO's efforts to automate its studies appear promising. ■

What's Next

With an annual megawatt cap in place, MISO is one step closer to restarting processing on its 309-GW interconnection queue after a more than yearlong hiatus on accepting new queue cycles.

MISO News

MISO Unveils Later Timeline for Queue Processing Restart

By Amanda Durish Cook

MISO is pushing back a restart of its swamped generator interconnection queue by a few months while it tries to study through the backlog with tech company Pearl Street.

The RTO now plans to finish the first phase of studies on the 2022 batch of project proposals before it begins studying the 2023 class in May. It won't begin analyzing 2025 entrants until the fourth quarter. However, MISO hopes to have all projects striking interconnection agreements over 2026, with the 2022 cycle proceeding in the second quarter, 2023 in the third quarter and 2025 by the end of 2026.

Last year, MISO tentatively scheduled the 2025 cycle of queue projects to begin in the third quarter. It also said it would begin studying the 123 GW of 2023 interconnection requests in February. (See *2023 Queue Cycle Delayed into 2025 as MISO Seeks Software Help on Studies*.)

MISO skipped acceptance of a 2024 queue class altogether. The RTO hasn't processed a new queue cycle in more than a year, saying it needs to introduce study automation and implement a megawatt cap to make processing requests less daunting. (See *MISO to Skip 2024 Queue Cycle While it Automates Study Process with Tech Startup*.)

It is betting that Pittsburgh-based tech startup Pearl Street's *SUGAR* (Suite of Unified Grid Analyses with Renewables) can get its over-taxed queue down to a one-year process.

Pearl Street and MISO are automating several aspects of the queue, including the studies that select network upgrades and estimate costs, study reports, and the process behind power flow model building, dispatching and solving.

In a teleconference Jan. 28, MISO's Ryan Westphal told the Interconnection Process Working Group that the RTO is "testing and getting things tuned in" on the automated work.

Why This Matters

The delay while MISO gets its queue study process automated means the RTO would begin processing the 123 GW of interconnection requests it received in 2023 this May instead of February.

Sheep grazing in the shadows of Minnesota Power's Sylvan Solar Project | *Minnesota Power*

Westphal said that while MISO and Pearl Street have made "significant progress" on implementing SUGAR, they "need a little more time" to refine the process and make it more user friendly as stakeholders have requested.

He said that by Feb. 10, MISO will begin using Pearl Street in earnest on the proposals that entered the queue in 2022. It hopes to finish the first phase of interconnection studies for the 2022 cycle by early May.

Westphal said MISO is choosing to complete the 2022 cycle's first phase studies before it starts on 2023's class to limit ambiguity in study results. He said a prior cycle's resources become assumptions in future study cycles, so MISO should avoid study overlap. The sheer size of the 2022 and 2023 queue cycles — 171 GW and 123 GW, respectively — also makes some separation a wise call.

"The 2022 cycle is large, as everyone remembers, so it's really prudent to get it through the queue," Westphal said.

Westphal said at this point, MISO plans to kick off the 2022 cycle on Feb. 10 and the 2023 cycle on May 5. The RTO hopes the technology can help it shrink the first phase of studies to 90 days.

It further estimates that SUGAR will reduce time spent on the 2022 and 2023 cycles by anywhere from 270 to 365 days, a "massive engineering time savings."

"We have to move through the backlog to get through to the place we want to be," Westphal said. He predicted "a lot of work" and MISO continuing to process simultaneous cycles until it can cut its queue down to a one-year interconnection process.

"We think that SUGAR gives us the best chance to do that," Westphal said. "We're hoping this is a big piece of us being able to achieve a one-year queue process."

The RTO also hopes that SUGAR can speed up the first phase of interconnection studies in particular so its engineers can devote more attention to the more intricate, back-end studies of the queue, Westphal said. ■

MISO News

FERC Rejects Blanket Extension of MISO COD Deadlines for Gen Developers

By Amanda Durish Cook

Why This Matters

Generation developers that entered the MISO queue in 2018 and 2019 must continue to appeal to FERC individually if they cannot meet their commercial operation date deadlines set by MISO. FERC rejected MISO's attempt to apply a sweeping, two-year extension for projects plagued by supply chain hurdles.

FERC has rejected MISO's attempt to implement a blanket, two-year extension of commercial operation dates for generation developers that entered the interconnection queue about seven years ago.

FERC said MISO's proposed waiver of its usual operations deadline was neither limited in scope, nor did it address a concrete problem (*ER25-150*). That leaves generation developers who entered the queue in 2018 or 2019 and need extra time to place projects in service appealing to FERC on a case-by-case basis.

MISO in recent years has experienced generation developers struggling to bring projects online according to the commercial operation dates they specified when entering the queue. The RTO said supply chain issues have developers even exceeding its three-year grace period, leaving many developers to apply for waivers of MISO's deadlines with FERC to avoid project cancellation.

MISO is working on a plan to allow projects up to nearly 11 years to enter service after the project entered the queue's definitive planning phase for studies; however, that proposal would apply only to projects that entered the queue in 2020 or later. (See *MISO to Relax Commercial Operation Deadlines in Interconnection Queue*.) For the approximately 200 developers that entered projects in the 2018 or 2019 queue cycles, MISO proposed a simpler, two-year waiver.

But FERC said MISO didn't show that the proposed waiver of its tariff would apply only to interconnection customers that still are unable to achieve commercial operation after the grace period. The commission said the waiver could extend to developers who may not need it.

"While we appreciate the desire for administrative efficiency by combining multiple interconnection requests facing a similar fact pattern into the same waiver request, administrative efficiency cannot come at the expense of providing sufficient information to demonstrate that the request meets the commission's waiver criteria," FERC said.

FERC also said MISO did not explain why a two-year extension is sufficient for all 2018 and 2019 projects to reach operations or attempt to demonstrate that projects are at risk without the blanket waiver.

"While MISO and some commenters have provided general details of lead time delays, MISO has not provided sufficient information regarding the practical effects of these lead times for each interconnection request in the 2018 and 2019 DPP study cycles," FERC said.

The commission said while it wouldn't entertain an across-the-board waiver, individual interconnection customers remain free to approach FERC when time is running out on their commercial operation deadlines.

MISO says its developers are bogged down by long lead times on acquiring transformers, breakers, panels and inverters. It sought the mass extension to lessen the risk of interconnection request terminations. EDP Renewables, Cordelio, Invenergy, NextEra and MISO's Independent Power Producers supported the waiver, while MISO South state regulators said a broad waiver would "eliminate the need for submission of numerous project-specific waiver requests by developers." ■

Entergy Mississippi's Sunflower Solar Station | *Entergy*

NYISO News

FERC Accepts NYISO Demand Curve Reset

By Vincent Gabrielle

FERC on Jan. 28 accepted NYISO's proposed tariff revisions that were submitted as part of the Demand Curve Reset, including setting a two-hour lithium-ion battery energy storage system (BESS) as the proxy peaking plant for use in determining the curve for the next four years (*ER25-596*).

In doing so, the commission dismissed protests from the Independent Power Producers of New York, the Market Monitoring Unit, the Electric Power Supply Association and Ravenswood Operations, among others, finding that NYISO and its consultants had identified the lowest-cost option for a hypothetical peaker plant.

The DCR is a quadrennial process that examines the cost of new entry for a hypothetical peaking plant and the likely revenue the plant would earn from participating in the capacity market. The difference between the likely cost and likely revenue illustrates what the hypothetical plant would need to earn from the capacity market to support market entry.

The latest reset was contentious, frequently driving meetings of the Installed Capacity Working Group past their allotted times with stakeholder discussion, feedback and arguments.

Some of these arguments continued in the FERC filing process with opponents' protests. IPPNY and the MMU told FERC that the two-hour BESS was ill considered from a capacity accreditation factor perspective in that such units would experience price volatility.

FERC headquarters in D.C. | *© RTO Insider LLC*

IPPNY and EPSA asserted that NYISO did not account for the financial risks adequately in BESS development. And IPPNY, the MMU and Ravenswood argued that two-hour BESS units were unable to meet transmission security needs.

FERC rejected these arguments, finding many of them to be speculative and that NYISO's proposed cost of equity and debt for a BESS peaker was "justified."

"Based on the record before us, we disagree with protesters that the two-hour BESS technology option will not provide adequate price signals to support the construction of new resources, and the retention of existing resources, to maintain NYISO's system reliability," FERC said. "For example, the New York Transmission Owners's analysis suggests that capacity costs could increase by 37% due to NYISO's selection of the two-hour BESS."

The commission also found that arguments about transmission security were "misplaced," as NYISO's service tariff does not require the ISO to consider a peaking plants contribution to transmission security.

"Moreover, NYISO states that it has commenced a multiyear collaborative process with its stakeholders to evaluate potential enhancements to its current capacity market to value resource contributions to transmission security," it said. "We believe that the separate stakeholder process is the appropriate forum to address any potential transmission security concerns." ■

NYISO CEO Lays out 2025 Priorities

By Vincent Gabrielle

NYISO CEO Rich Dewey opened the Management Committee on Jan. 29 with a congratulations on getting through 2024 before looking ahead to the rest of 2025.

"We had a lot on our plate, very complicated matters that needed to be navigated through the stakeholder process. Sometimes contentious. Sometimes not," Dewey said. "I do want to express my appreciation to stakeholders for continuing to work through the issues and tee us up for, I think, an equally challenging 2025."

Dewey said his "first priority" is maintaining grid reliability. Load forecasting and managing uncertainties are going to be paramount as large loads continue to come online.

"Specific to this are the large loads that we've seen based on economic development, or some of the AI-driven, business-centric data center applications that can pop up pretty quickly," Dewey said. "Managing that and making sure we've got a good, reliable system to deal with those uncertainties is going to be a big part of our forecasting team's priorities."

He went on to say that the 2024 Reliability Needs Assessment would "transition forward" to the Comprehensive Reliability Plan this year. In all its reliability, planning and forecasting, NYISO is facing challenging levels of uncertainty, and new, innovative methods will be needed to address it, he said.

Dewey said meeting the needs of the system would require looking at the market structures, rules and planning processes in place to ensure that they continue to provide reliability through appropriate market signals. He pointed to the complexities of 2024's Demand Curve Reset, saying the ISO had heard the feedback from stakeholders and was committed to examining the design principles of the capacity market. (See related story, *FERC Accepts NYISO Demand Curve Reset*.)

NYISO CEO Rich Dewey | *NYISO*

This will occur alongside the monumental shift in transmission planning required by FERC Order 1920. NYISO is going to have to balance this new long-term regional transmission planning regime while working through the inaugural state Coordinated Grid Planning Process. Dewey said this would require a "tremendous amount of work" in 2025 to meet the needs of stakeholders and position the ISO for an uncertain future.

"I believe we've got some of the leading markets, if not the leading markets, in the nation," Dewey said. But with all the new technologies and transitions occurring industry wide, "we need to continue to stay out ahead of that."

Operations Report and Winter Reliability

The committee also heard COO Emilie Nelson's *report* on December 2024's market performance. The average locational-based marginal price was $73.20/MWh, which was higher than the $35.26/MWh for November 2024 and $33.67/MWh for December 2023.

Both the day-ahead and real-time load-weighted LBMPs were higher than in the previous month. The average year-to-date monthly cost was $44.67/MWh, up 14.2% over December 2023. This correlates with higher sendouts, 432 GWh/day on average compared to 377 GWh/day in November. Natural gas prices were also higher.

"I'd like to call out that, of course, we had some pretty significant cold temperatures last week, spanning [Jan. 20 to 22]," Nelson said. The peak load was 23,521 MW and occurred Jan. 22, a Wednesday.

She expressed her gratitude for the communication across the cold-stressed system.

"Although the neighboring control areas were also operating through tight system conditions, all areas were projected [to achieve,] and then realized, reliable operation," Nelson said. "It was a situation where the coordination of power flows provided greater regional reliability." ■

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PJM News

PJM, Shapiro Reach Agreement on Capacity Price Cap and Floor

By Devin Leith-Yessian

PJM announced Jan. 28 it will seek to establish a $325/MW-day price cap on capacity prices and a $175/MW-day floor for the 2026/27 and 2027/28 Base Residual Auctions (BRAs) following discussions with Pennsylvania Gov. Josh Shapiro to resolve a complaint he filed over increased capacity costs.

The RTO has scheduled a special session of the Members Committee on Feb. 7 to consult with stakeholders on the prospective Federal Power Act Section 205 filing, with meeting materials expected on Jan. 31. Consultation with transmission owners also would be necessary. PJM spokesperson Susan Buehler said the specifics of the proposal will be discussed Feb. 7 and clarified that the price cap and floor would extend to all zones.

The 2026/27 BRA is scheduled to be conducted in July, with several pending filings at FERC seeking changes to the auction design and stakeholder processes envisioning even more. Across several of those dockets, PJM has requested orders by Feb. 21, which it stated is necessary to ensure it has adequate time to implement the changes in time for the auction.

The RTO noted that any changes are "subject to consultation with the PJM members and the PJM Board of Managers."

"PJM did the right thing by listening to my concerns and coming to the table to find a path forward that will save Pennsylvanians billions of dollars on their electricity bills," Shapiro said in his own *announcement*. "My administration will continue to work to ensure safe, reliable and affordable power for Pennsylvanians for the long term."

In his complaint and letters to PJM's board, Shapiro argued that the current price cap structure, which takes the greater of the gross cost of new entry (CONE) or 1.75 times net CONE, would result in total capacity costs $20.4 billion beyond what is necessary to maintain resource adequacy. (See *PJM in Discussions with Gov. Shapiro on Capacity Price Cap*.) The complaint sought to rework that formula to 1.5 times net CONE, arguing that would be the highest price necessary to ensure the reference resource, a combustion turbine, is profitable (*EL25-46*).

Why This Matters

With PJM's next capacity auction scheduled for July, and several proposed revisions to the market pending before FERC, the intervention by a single state's governor has added yet another unknown variable to the mix.

The governors of New Jersey, Maryland, Illinois and Delaware filed comments and sent letters supporting Pennsylvania's complaint.

In a statement, Maryland Gov. Wes Moore's office said he appreciates PJM's responsiveness to mitigate unnecessarily high capacity prices.

"Today's announcement of a path toward resolving a complaint filed by Pennsylvania — that was backed by Maryland and other states served by PJM — shows the grid operator has an understanding of the need to limit the future impacts of major price hikes on our ratepayers," it said. "The governor remains concerned that while PJM has agreed to cap electricity costs, successful implementation of this approach depends on details that need to be worked out ahead of federal approval."

Mila Myles, spokesperson for Delaware Gov. Matt Meyer, said he shares the other governors' concerns about potential capacity cost increases.

"We welcome the news that PJM has reached a tentative settlement that will protect consumers in Delaware and other states from excessive increases in their electric bills," she said in an email. "This is an example of how PJM can work with states to ensure that our constituents are protected from abrupt changes in energy markets."

Paul Sotkiewicz, president of E-Cubed Policy Associates, told *RTO Insider* the agreement follows years of PJM being influenced by stakeholders to change market rules that disadvantage them, showing an institutional vulnerability that opens the door to any parties filing FPA Section 206 complaints and negotiating directly with PJM staff to satisfy politically driven interventions. He called the prospective price floor "window dressing" given the likelihood PJM and members discussed high prices in the 2026/27 auction.

"This is no longer a market when you're just picking prices," he said. "This is how wholesale

Pennsylvania Gov. Josh Shapiro | *Shutterstock*

markets die."

In addition to the direct impact of suppressing prices in the coming auctions, he argued that the repeat rule changes undermine investor confidence in the prices set by the capacity market. He noted that generation deactivation requests have been filed for the Elwood plant, owned by J-Power USA, and Avenue Capital Group's Elgin generators in the ComEd zone. While Elgin has rescinded its request to retire following the 2025/26 price print, Sotkiewicz said the decision to continue Elgin on the path to deactivation makes sense even in the face of near-term high prices given the volatility PJM has created.

"You can't run a market this way; there's no way an investor can have confidence in a ruleset," he said. "I have more certainty about building a generator in California than PJM."

Sotkiewicz said the process of negotiating directly with one governor on the market design for an RTO with 14 jurisdictions and market participants who will be directly affected tells stakeholders that their perspectives don't matter. He said PJM repeatedly has eschewed the stakeholder process to instead follow various special processes, often giving minimal notice to members before filing major redesigns on the capacity market.

"Why are we having a stakeholder process about anything when you're just going to do whatever the hell you want?" ■

Constellation and Calpine Propose Selling PJM Plants to Cut Market Power

By James Downing

PSEG's Bethlehem Energy Center | *PSEG*

Constellation Energy and Calpine Corp. asked FERC to approve their proposed merger and offered to sell off most of the latter's natural gas fleet in PJM to assuage market power concerns (*EC25-43*). (See *Constellation to Acquire Calpine for $29.1B*.)

"The combined company will have a geographically diverse coast-to-coast presence and operate the most reliable and cleanest generation portfolio in the country," the firms told FERC. "This will allow the company to better serve customers with a broader array of energy and sustainability products to power homes and businesses at competitive prices while continuing to provide reliable, clean and secure generation to the grid."

Calpine has a large presence in California, where Constellation is not very active, and the two overlap a little in New England, New York and the Midcontinent ISO, but their biggest overlap is PJM and specifically the eastern part of the RTO.

The two firms proposed selling all but one of Calpine's combined cycle natural gas plants in PJM, which totals 3,546 MW. The units that will go on sale if FERC approves the application are valuable and high-performing plants, and two of them are dual-fuel capable.

The plants proposed for sale are the 1,134-MW Bethlehem Energy Center, the 569-MW York Energy Center 1, the 1,136-MW Hay Road Energy Center and the 707-MW Edge Moor Energy Center.

Eastern PJM is the one area where the combined generation of Constellation and Calpine led to violations of market power screens. The application argued that those failures "do not reflect actual competitive concerns" because the region no longer should be considered a submarket, and Constellation's bids already are covered by an agreement with PJM's market monitor.

"Nevertheless, to avoid a potentially protracted regulatory proceeding and speed the governmental approval process, applicants commit to a robust mitigation plan that would involve the divestiture of all but one of Calpine's combined cycle natural gas plants located in eastern PJM," the application said. "As described below, that mitigation plan would eliminate all screen violations in these PJM submarkets."

Without the sales, the combined firm would own more than 25 GW of generation in PJM, which compares to just 8 GW in California and less in other markets.

Constellation owns 2.3% of CAISO's generation now and Calpine 13.4%, but their combination would have a minimal impact on market power there, the application argued.

In PJM, Constellation owns 11.4% of the generation and the deal would bring an additional 3% under its corporate umbrella. The consultants hired by the merging firms argued that the submarkets FERC has looked at historically in PJM no longer make sense. Still, they said, the mitigation plan would eliminate market screen failures in all of them.

There should be enough buyers that do not have significant ownership in PJM for the four power plants, but the application noted that FERC can review any potential buyers if it approves the Constellation-Calpine deal.

For any period between the merger's close and the sale of the four power plants, Constellation said it would abide by voluntary mitigation that keeps its bids in the relevant PJM submarkets near its generators' costs. ■

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Southeast

TVA CEO Jeff Lyash Announces Plans to Retire

By James Downing

Tennessee Valley Authority CEO Jeff Lyash announced plans to retire "no later than the end of the fiscal year" after running the federal power authority for nearly six years.

"For the past six years, it's been my privilege to serve with an experienced, talented team at TVA," said Lyash. "TVA truly is a special place — created more than 90 years ago to improve the quality of life for more than 10 million people across this region. That mission of service continues to be our focus today."

President Donald Trump *criticized* Lyash's high salary back in his first term and the announcement comes less than two weeks into his second, but TVA's press release was a standard retirement announcement and the end of the fiscal year means he could stay on until this fall. TVA is not taxpayer funded and gets its revenue from power sales.

"I grew up in the small coal-mining town of Shamokin, Pennsylvania, and I cannot think of a better place than TVA to close out my career serving people just like those in my hometown," Lyash said. "While I'm looking forward to my next chapter, spending more time with family, grandchildren and friends, I will miss our TVA team and the relationships we've built across this region."

Before joining TVA, Lyash was the CEO of Ontario Power Generation and worked for years at Duke Energy and Progress Energy.

Lyash was appointed to the job in April 2019 and since has run the country's largest public utility with a focus on building strong partnerships, including with the TVA region's 153 local power companies, and managing sustained growth.

"Jeff's knowledge and experience make him one of the top leaders in the energy industry," said TVA Board Chair Joe Ritch. "Jeff has done more than lead one of the nation's top power providers, he has helped drive an industry forward. His vision has positioned TVA well for the future, and he has built a legacy that will endure."

TVA has below average electricity rates and it has been meeting ever-growing demand, with more than 3,500 MW of new generation under construction or online as of early 2025. The authority saw its all-time peak this January when demand hit 35,319 MW.

Why This Matters

TVA is the country's largest public utility, serving 153 local power companies with low electricity rates amid ever-expanding load growth. TVA also is positioned to build a small modular reactor.

Lyash positioned TVA to be a leader on new nuclear power, with the authority winning approval for an early site permit from the Nuclear Regulatory Commission to possibly build a small modular reactor. TVA is leading an application with 11 industry partners and the state of Tennessee for an $800 million grant from the U.S. Department of Energy to build that SMR.

"Nuclear is the most reliable and efficient energy the world has ever known, and TVA is uniquely positioned to help drive this forward," Lyash said. "Advanced nuclear technologies will play a critical role in our region and nation's drive towards great energy security." ■

TVA CEO Jeff Lyash | *TVA*

Southeast

ACORE Presses Congress to Order Improvements in TVA Planning, Oversight

By Amanda Durish Cook

TVA crews rebuilding lines in 2020 after tornadoes in Middle Tennessee | *TVA*

The American Council on Renewable Energy (ACORE) says Congress could take steps to establish more comprehensive transmission and generation planning within the Tennessee Valley Authority.

ACORE published a new *report* ahead of a Jan. 30 webinar, suggesting Congress ensure the TVA board of directors has access to outside expertise; order TVA to engage in comprehensive transmission planning; bring the utility under FERC jurisdiction; require more transparency; and investigate how it could best plan resources, transmission and interconnection.

ACORE said projections of increasing load in the Tennessee Valley and TVA relying on imports to manage peak load mean it is time for Congress to consider modernizing the utility's management.

Jonathan Geldof, lead author of the report and senior manager of government affairs for ACORE's Macro Grid Initiative, said that with TVA's draft integrated resource plan laying out 30 possible portfolios, its board members — who are not required to have experience in the electric industry — seem ill equipped to determine the most realistic path. Geldof said Congress should ensure the board can access independent staff, like at a state public service commission, or use an Independent Market Monitor, akin to those in RTOs, to get advice.

The webinar occurred a day before TVA CEO Jeff Lyash announced his retirement after about six years with the federal utility. (See related story, *TVA CEO Jeff Lyash Announces Plans to Retire*.)

TVA is conducting integrated resource planning through 2035. The draft IRP *estimates* it will need 9 to 26 GW in new firm capacity, resulting in a 75 to 90% reduction in carbon emissions from a 2005 peak.

The Bottom Line

Among the steps ACORE wants Congress to take are making sure TVA board members have access to independent industry experts and requiring more transparency in the utility's generation and transmission planning.

In its report, ACORE said the draft IRP is so broad that it could "serve to justify whatever action TVA chooses to take." It also said the utility's board is "woefully ill equipped to provide the kind of feedback [that] would serve as a check on TVA."

ACORE noted that with TVA set to reach its borrowing limit in the coming years, it's an opportune time for Congress to condition funding increases on administrative improvements.

Geldof said the valley is poised for data centers, including an *expansion of Colossus*, a supercomputer built by Elon Musk's artificial intelligence startup, xAI. On the other hand, he said, TVA faces 7 GW of retirements over the next few years.

"What all those scenarios have in common is that TVA is going to need a lot more generation in the coming years," Geldof said.

TVA recently set an all-time peak demand *record* of 35.3 GW on Jan. 22 during a cold snap in which systemwide temperatures averaged 11 degrees Fahrenheit. However, ACORE said TVA was only able to meet demand through 20% imported power.

Integrated Transmission Planning

Additionally, TVA is undergoing an integrated transmission plan for the first time in its history. But Geldof said any ensuing transmission portfolio will not be as valuable as it could be unless it is planned in concert with the IRP. TVA is tackling the two under independent processes.

"When you consider generation and transmission separately, that's not really an integrated plan," he said.

Geldof said that like much of the Southeast, TVA also needs interregional transmission. He pointed out that while TVA was initiating

Southeast

ACORE's panel, "TVA's Transmission Troubles," underway on Jan. 30 | *ACORE*

rolling blackouts during the December 2022 winter storm, neighbor SPP was curtailing excess wind generation in its footprint.

Congress should also order a relaxation of TVA's "fence," Geldof said, which suppresses competition. He was referring to a 1959 addition to the TVA Act that prohibits the utility from selling its electricity into wholesale markets outside of its territory and prohibits its local power companies from purchasing power from its neighbors.

"They could open a 'gate,' to expand the metaphor … or they could take down the fence altogether," Geldof said of Congress, though he added that large utilities in the valley would likely resist removal of the wheeling restriction.

Southern Renewable Energy Association (SREA) Executive Director Simon Mahan said the group applied to be a stakeholder in TVA's integrated transmission process but was denied and shut out of meetings.

From what he can tell, Mahan said, TVA's transmission planning is "radically different" than that of nearby MISO, where planners hold consistent public meetings, are available for discussion and do not gatekeep planning information. He said SREA is concerned that TVA is "just now stepping into" long-term, scenario-based transmission planning but is seemingly refusing help from those that have contributed to comprehensive planning in RTO footprints.

"It's a missed opportunity from public power to take feedback from some of the areas that have best practices and really kind of shut down those discussions before they get started," Mahan said.

Mahan also said the TVA board receives limited information and currently does not get the "gut check" that analysis from independent third parties provides.

"It's not that we're criticizing the board for making bad decisions. It's just that they are not given enough information to know, 'Is this truly the best decision at the right time?'" he said.

Maggie Shober, research director at the Southern Alliance for Clean Energy, said TVA should settle on the most probable path forward in an IRP instead of simply using its lowest-end and highest-end estimates, which have it installing anywhere between a few hundred megawatts and several gigawatts of solar capacity.

"TVA's past IRPs have been overly broad." The public should reach out to the TVA and its board to urge more specific resource planning, she said. Many in TVA's leadership come from C-suites in investor-owned utilities that are accustomed to meeting load growth with natural gas plants. Shober said it's incumbent on her organization and others to "break them out of that."

Myra Sinnott, of solar developer Silicon Ranch, said more transparent oversight would make building generation in TVA easier.

Sinnott said trying to develop in TVA is a "chaotic" process, with requirements continually changing with no clear indication.

"It's like Whac-A-Mole sometimes. … You feel a little hamstrung working in a black hole," Sinnott said. "It tends to be a more complicated process working in TVA than in other regions. … It would be easier if things were a little more consistent."

Finally, panelists agreed that the Trump administration's efforts to bolster fossil fuels would not grind the clean energy transition to a halt or render renewable generation an unsafe bet.

Mahan said TVA's resource needs are coming fast through a combination of load growth and aging generation. He said scuttling renewable energy plans in favor of fossil fuel generation does not make economic sense and would strain the supply chain for natural gas components.

"If we're going to be building big stuff again on the load side, we have to have as many tools in our toolbox as possible," he said.

"I feel like the cow is already out of the barn," Sinnott said. "It's going to take a lot more than four years to slow it way down."

Shober said she thinks TVA has an overreliance on gas already given its current generation portfolio. She argued that TVA's increasing reliance on gas will not help it become more reliable and could introduce volatility into rates through oscillating fuel prices. ■

Company Briefs

GE Vernova to Build Utility-scale Inverters at US Plant

GE Vernova announced plans to manufacture utility-scale inverters at a facility in Pittsburgh.

GE debuted the 2,000-V DC inverter last September in a multi-megawatt solar park as part of a pilot installation in North America, which is expected to be operational early this year. The facility will start production with its 1,500-V DC model, although the manufacturing line is ready to accommodate both its 1,500-V DC and its 2,000-V DC models.

The investment is part of a broader investment of more than $560 million the company plans to infuse into its U.S. operations over the next two years.

More: *pv magazine*

KORE Power Abandons Planned $1B Battery Plant

KORE Power last week announced it is abandoning plans for a $1 billion lithium-ion battery plant in Arizona.

The decision, which was attributed to the company "restructuring," comes more than two years after KORE broke ground on the facility.

More: *Arizona Republic*

Vesper Energy Completes 600-MW Texas Solar Project

Vesper Energy last week announced it has completed its 600-MW Hornet Solar project in Texas.

The project is composed of more than 1.36 million PV panels on 6 square miles of land. It remains on track to be operational by spring.

More: *Vesper Energy*

Microsoft, Chestnut Carbon Reach Removal Credit Deal

Chestnut Carbon, a nature-based carbon removal company, last week announced it has agreed to a 25-year deal with Microsoft to provide the tech giant with removal credits from its projects in Arkansas, Texas and Louisiana.

The deal, the financials of which were not publicly disclosed, would deliver more than 7 million tons of carbon removal credits to Microsoft. It involves the restoration of 60,000 acres of land by planting more than 35 million native, biodiverse hardwood and softwood trees.

More: *Axios*

Federal Briefs

TVA Names Rice CFO

The Tennessee Valley Authority has named Tom Rice as its chief financial officer, effective Jan. 27.

Rice joined TVA in 2002 and has served in a variety of leadership roles, including senior vice president for finance, treasurer and chief risk officer, and vice president of financial operations and performance.

Rice will succeed John Thomas, who announced his intent to retire in December.

More: *TVA*

USDA Ordered to Scrub Climate Change from Websites

Agriculture Department employees have been ordered to delete landing pages discussing climate change across agency websites and document climate change references for further review, according to an internal email obtained by POLITICO.

The email calls on website managers to "Identify and archive or unpublish any landing pages focused on climate change" and "Identify all web content related to climate change and document it in a spreadsheet" for the office to review.

More: *POLITICO*

State Briefs

CALIFORNIA

PUC Approves SCE Rate Hike to Cover Wildfire Victim Payments

The Public Utilities Commission last week unanimously voted to allow Southern California Edison to raise rates to cover payments it made to victims of the devastating 2017 Thomas wildfire.

The PUC approved the rate hike without discussion. The vote means that more than $1.6 billion of the $2.7 billion Edison paid to more than 5,000 fire victims will be

covered by customers. The rest will be paid by shareholders. Most customers will see an increase to their monthly bill of about $1, the company said.

SCE also asked the PUC to approve a second rate increase for $5.4 billion in payments to victims of the 2018 Woolsey fire, which it will consider later.

More: *Los Angeles Times*

CONNECTICUT

Eversource, Avangrid Sue PURA over Decision-making Process

Eversource Energy and Avangrid last week sued the Public Utilities Regulatory Authority, saying Chair Marissa

Gillett has frozen the agency's other commissioners out of the decision-making process since the start of 2020.

As a result, the lawsuit states hundreds of decisions involving the utilities and their subsidiaries have been affected. Last month, some Democratic lawmakers accused the utilities of trying to intimidate public officials. Meanwhile, Republican leaders said the litigation signifies problems with the regulatory system.

Gov. Ned Lamont later responded to the lawsuit, publicly accusing the utilities of waging a campaign to oust Gillett, whom he appointed.

More: *CT Insider*; *CT Mirror*

INDIANA

URC Approves Duke Rate Increase

The Utility Regulatory Commission last week approved a $395 million rate increase for Duke Energy.

Duke originally requested an increase of $491.5 million, which would have raised average residential bills by as much as $27.63/month in two phases.

More: *WXIN*

MARYLAND

Talen, PJM Reach Agreement to Keep Coal, Oil Generation Online

Talen Energy last week reached an agreement with PJM and the Public Service Commission to extend operations at its 1.3-GW coal-fired Brandon Shores power plant and 774-MW oil-fired H.A. Wagner units until May 31, 2029.

Talen on Jan. 27 said the agreement is "intended to provide the power necessary to maintain grid and transmission reliability in and around the City of Baltimore until necessary transmission upgrades to provide reliable power to the area from other sources are complete."

If approved by FERC, the settlement will allow Talen to run the plants well beyond their May 2025 retirement dates.

More: *POWER Magazine*

MINNESOTA

Gov. Walz Appoints Partridge to PUC

Gov. Tim Walz last week appointed Audrey Partridge to a six-year term on the Public Utilities Commission.

Partridge was the policy director at the Center for Energy and Environment. Before joining CEE in 2017, she spent five years at CenterPoint Energy.

Partridge is replacing Valerie Means, who did not apply for reappointment.

More: *The Minnesota Star Tribune*

MISSOURI

Utilities Push Legislation to Charge Customers Upfront to Build Gas Plants

Evergy and Ameren last week asked the House Utilities Committee to support legislation that would allow them to charge customers for natural gas power plants before they're completed.

The utilities say the state is losing out on attracting major employers because it doesn't have enough power supply. However, environmental and consumer advocates say the legislation, known as "construction work in progress," just allows more profit for monopoly companies at the expense of consumers.

More: *Missouri Independent*

NORTH CAROLINA

Gov. Stein Announces Interim Utilities Commission Appointments

Gov. Josh Stein last week appointed Commissioner Floyd McKissick Jr. as chair of the Utilities Commission.

McKissick will replace Chair Charlotte Mitchell, who resigned, and carry out the remainder of her term through June 2029. He has served on the commission since 2019.

Stein also appointed Steve Levitas, a solar industry veteran and expert on energy policy, to fill McKissick's seat. Levitas will serve through this June.

More: *Office of the Governor*

OKLAHOMA

AG Files 3rd Lawsuit over 2021 Winter Storm Utility Rates

Attorney General Gentner Drummond filed a lawsuit on Jan. 9 in Osage County alleging artificially inflated natural gas prices during Winter Storm Uri in February 2021.

Drummond initially filed two lawsuits last April. The lawsuits claimed the state's gas companies violated the Oklahoma Antitrust Reform Act, the Oklahoma Common Carrier statute, breach of contract, unjust enrichment, fraud, constructive fraud, bad faith breach of contract, civil conspiracy and negligence with their actions during the storm. Drummond claims some companies had counted on higher demand with the arrival of the storm and schemed to artificially reduce supply.

As of Jan. 24, court records show no new filings in the case, and no actions are currently scheduled.

More: *The Oklahoman*

SOUTH DAKOTA

Eminent Domain Ban Passes House, Heads to Senate

The House of Representatives last week voted 49–19 to advance a bill that would ban the use of eminent domain for carbon dioxide pipelines.

Summit Carbon Solutions, who is vying to build a $9 billion CO_2 pipeline through the state, has voluntary easement agreements with some landowners to cross their land but needs eminent domain to gain access from those who are unwilling to sign easements.

The bill now heads to the Senate.

More: *South Dakota Searchlight*

TEXAS

Xcel Energy Amarillo Coal Plant to Switch to Natural Gas

Xcel Energy's Harrington Station, which opened its first unit in 1976 in Amarillo, will burn primarily locally produced natural gas beginning in May.

Xcel said it looked into other alternatives to reduce sulfur dioxide emissions, but shifting to natural gas was the most efficient option due to the aging units and costs.

More: *Amarillo Globe-News*

VERMONT

State Enacts EV Registration Fee

The state's Department of Motor Vehicles has notified drivers they will have to pay $178 a year to register their EVs beginning Jan. 1.

The fee is said to be twice as much as owners of internal combustion engine vehicles.

At least 39 states charge such annual fees.

More: *The New York Times*

VIRGINIA

Lawmakers' Proposal to 'Significantly' Cut Bill to Power Rates Moves Forward

A House of Delegates subcommittee last week voted 9-0 to advance a bill that lawmakers say would lower Appalachian Power customers' bills by "substantially" cutting the utility's profits and "significantly" reducing its rates.

The bill would require regulators to evaluate Appalachian's rates more often, prohibit rate increases from taking effect during the winter, and create a financing mechanism to shield customers from bearing the costs associated with storm-related repairs and power generation facilities. The average Appalachian residential bill has risen about $50 in the last three years.

The legislation now heads to the full House Labor and Commerce committee.

More: *Cardinal News*

Possum Point Power Plant to Expand, Modernize for Data Centers

Dominion Energy announced it will expand its Possum Point Power Station to meet rapidly ascending data center power needs.

Dominion will add 44 MW to the 660-MW facility via modernized gas and steam turbines.

The plant stopped burning coal in 2003 and has since burned oil and natural gas.

More: *InsideNoVa.com*

WYOMING

Lawmakers Kill Bill to Store Nuclear Waste

The House Minerals, Business and Economic Development Committee last week denied a bill that would have created a temporary nuclear waste storage facility.

Several lawmakers were not convinced that the "temporary" storage facility would be temporary. They noted the federal government has tried and failed for decades to establish a permanent nuclear waste repository that would give some legitimacy to the "temporary" storage concept.

More: *WyoFile*